INTEGRYS HOLDING, INC.
Form 10-Q
August 05, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from __________ to __________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-11337	INTEGRYS HOLDING, INC. (successor to Integrys Energy Group, Inc.) (A Wisconsin Corporation) 231 West Michigan Street Milwaukee, WI 53201 (414) 221-2345	47-1477787

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

Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes [X] No [ ]

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

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

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

Yes [ ]   No [X]

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

Common stock, $0.01 par value,
1,000 shares outstanding at
August 5, 2015

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For the Quarter Ended June 30, 2015
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Acronyms Used in this Quarterly Report on Form 10-Q

AMRP	Accelerated Natural Gas Main Replacement Program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
ICC	Illinois Commerce Commission
IES	Integrys Energy Services, Inc.
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC (doing business as Trillium CNG)
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
N/A	Not Applicable
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC (formerly known as WPS Power Development, Inc.)
PELLC	Peoples Energy, LLC (formerly known as Peoples Energy Corporation)
PGL	The Peoples Gas Light and Coke Company
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
UPPCO	Upper Peninsula Power Company
WBS	WEC Business Services, LLC (formerly known as Integrys Business Support, LLC)
WDNR	Wisconsin Department of Natural Resources
WEC	WEC Energy Group, Inc.
WPS	Wisconsin Public Service Corporation

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Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot provide assurance that such statements will prove correct.

Forward-looking statements involve a number of risks and uncertainties. Some risks and uncertainties that could cause actual results to differ materially from those expressed or implied in forward-looking statements include those described in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2014, as may be amended or supplemented in Part II, Item 1A of our subsequently filed Quarterly Reports on Form 10-Q (including this report), and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting the regulated businesses;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The impact of unplanned facility outages;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer energy use, customer growth, and our ability to adequately forecast energy use for our customers;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries' liquidity and financing efforts;
- The terms and conditions of the governmental and regulatory approvals of the WEC Merger could reduce anticipated benefits, and the ability to successfully integrate our operations with Wisconsin Energy Corporation;
- The effects, extent, and timing of competition or additional regulation in the markets in which our subsidiaries operate;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries' counterparties, affiliates, and customers to meet their obligations;
- The ability to use tax credit, net operating loss, and/or charitable contribution carryforwards;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;

- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- Potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed timely or within budgets;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The financial performance of ATC and its corresponding contribution to our earnings;
- The timing and outcome of any audits, disputes, and other proceedings related to taxes;
- The effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- The effect of accounting pronouncements issued periodically by standard-setting bodies; and
- Other factors discussed elsewhere herein and in other reports we file with the SEC.

Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS HOLDING, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)	Three Months Ended		Six Months Ended	
	June 30		June 30	
(Millions)	2015	2014	2015	2014
Operating revenues	$638.3	$837.1	$1,801.8	$2,475.4
Cost of sales	217.1	400.2	790.2	1,373.1
Operating and maintenance expense	268.0	318.0	540.1	662.4
Depreciation and amortization expense	72.1	72.8	147.5	144.2
Property and revenue taxes	17.9	17.2	36.1	34.7
Merger costs	59.3	5.9	60.0	5.9
Impairment loss on property, plant, and equipment at PDL	10.7	—	10.7	—
Gain on sale of certain PDL solar power generation plants	(5.2)	—	(5.2)	—
Operating (loss) income	(1.6)	23.0	222.4	255.1
Equity in earnings of transmission affiliate	22.4	23.0	39.4	45.5
Miscellaneous income	1.8	5.8	9.1	12.3
Interest expense	40.0	39.3	79.0	79.0
Other expense	(15.8)	(10.5)	(30.5)	(21.2)
(Loss) income before taxes	(17.4)	12.5	191.9	233.9
(Benefit) provision for income taxes	(8.1)	4.5	70.9	86.4
Net (loss) income from continuing operations	(9.3)	8.0	121.0	147.5
Discontinued operations, net of tax	—	(0.8)	(0.8)	12.1
Net (loss) income	$(9.3)	$7.2	$120.2	$159.6

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS HOLDING, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended		Six Months Ended	
	June 30		June 30	
(Millions)	2015	2014	2015	2014
Net (loss) income	$(9.3)	$7.2	$120.2	$159.6
Other comprehensive income, net of tax:				
Cash flow hedges				
Reclassification of net losses (gains) to net income, net of tax of $0.1 million, $ – million, $0.2 million, and $0.9 million, respectively	0.2	0.2	0.3	(0.4)
Defined benefit plans				
Pension and other postretirement benefit adjustments arising during period, net of tax of $0.4 million, $ – million, $0.4 million, and $(0.1) million, respectively	0.7	—	0.7	(0.1)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.6 million, $0.2 million, $1.1 million, and $0.5 million, respectively	0.9	0.5	1.6	0.8
Defined benefit plans, net	1.6	0.5	2.3	0.7
Other comprehensive income, net of tax	1.8	0.7	2.6	0.3
Comprehensive (loss) income	$(7.5)	$7.9	$122.8	$159.9

The accompanying condensed notes are an integral part of these statements.

INTEGRYS HOLDING, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (Millions, except share and per share data)	June 30 2015	December 31 2014
Assets		
Cash and cash equivalents	$156.3	$ 18.0
Accounts receivable, net of reserves of $55.2 and $60.3, respectively	341.6	480.7
Receivables from related parties	27.3	—
Accrued unbilled revenues	110.6	266.4
Materials, supplies, and inventories	234.1	327.7
Assets held for sale	—	51.5
Deferred income taxes	119.4	52.4
Prepaid taxes	77.2	136.2
Other current assets	80.7	57.4
Current assets	1,147.2	1,390.3
Property, plant, and equipment, net of accumulated depreciation of $3,227.2 and $3,322.0, respectively	7,098.2	6,827.9
Regulatory assets	1,582.0	1,585.3
Equity investment in transmission affiliate	552.0	536.7
Goodwill	655.4	655.4
Other long-term assets	276.6	286.4
Total assets	$11,311.4	$ 11,282.0
Liabilities and Equity		
Short-term debt	$314.4	$ 317.6
Current portion of long-term debt	180.0	125.0
Accounts payable	435.1	490.7
Payables to related parties	1.8	—
Energy costs refundable through rate adjustments	69.0	44.8
Liabilities held for sale	—	13.8
Other current liabilities	303.8	348.7
Current liabilities	1,304.1	1,340.6
Long-term debt	2,901.3	2,956.3
Deferred income taxes	1,692.9	1,570.0
Deferred investment tax credits	65.0	60.6
Regulatory liabilities	492.6	508.8
Environmental remediation liabilities	576.2	579.9
Pension and other postretirement benefit obligations	275.6	274.6
Asset retirement obligations	491.0	479.1
Other long-term liabilities	189.2	161.3
Long-term liabilities	6,683.8	6,590.6
Commitments and contingencies		
Common stock – $0.01 par value; 1,000 shares authorized, issued, and outstanding at June 30, 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	2,699.3	2,642.2
Retained earnings	619.9	626.0
Accumulated other comprehensive loss	(25.0)	(27.6)
Shares in deferred compensation trust	(21.8)	(20.9)
Total common shareholders’ equity	3,272.4	3,299.7
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding	51.1	51.1
Total liabilities and equity	$11,311.4	$ 11,282.0

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS HOLDING, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(Millions)	Six Months Ended June 30 2015	2014
Operating Activities		
Net income	$120.2	$159.6
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization expense	149.9	147.9
Deferred income taxes and investment tax credits, net	58.3	83.4
Pension and other postretirement contributions	(6.2)	(69.5)
Goodwill impairment loss	—	6.7
Impairment loss on property, plant, and equipment at PDL	10.7	—
Gain on sale of certain PDL solar power generation plants	(6.1)	—
Changes in working capital		
Accounts receivable and accrued unbilled revenues	274.2	136.1
Inventories	97.4	30.9
Other current assets	26.4	96.3
Accounts payable	(67.5)	(15.8)
Other current liabilities	47.0	0.3
Other, net	(30.7)	15.2
Net cash provided by operating activities	673.6	591.1
Investing Activities		
Capital expenditures	(424.5)	(337.9)
Investment in transmission affiliate	(3.4)	(10.2)
Cost of removal, net of salvage	(7.0)	(6.4)
Rabbi trust funding related to change in control	(14.3)	(65.0)
Withdrawal of restricted cash from Rabbi trust for qualifying payments	14.1	—
Proceeds from sale of certain PDL solar power generation plants	47.6	—
Purchase of natural gas distribution business in Minnesota	(11.0)	—
Other, net	2.8	(10.3)
Net cash used for investing activities	(395.7)	(429.8)
Financing Activities		
Exercise of stock options	4.1	11.9
Purchase of common stock	(23.9)	(29.3)
Dividends paid on common stock	(108.2)	(108.2)
Retirement of long-term debt	—	(100.0)
Change in short-term debt	(3.2)	94.7
Other, net	(8.4)	(7.7)
Net cash used for financing activities	(139.6)	(138.6)
Net change in cash and cash equivalents	138.3	22.7
Cash and cash equivalents at beginning of period	18.0	22.3
Cash and cash equivalents at end of period	$156.3	$45.0
Cash paid for interest	$74.9	$74.5
Cash received for income taxes	$(45.4)	$(59.2)

The accompanying condensed notes are an integral part of these statements.

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INTEGRYS HOLDING, INC.
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
June 30, 2015

Note 1—Basis of Presentation

As used in these notes, the term "financial statements" refers to the condensed consolidated financial statements. This includes the condensed consolidated statements of income, condensed consolidated statements of comprehensive income, condensed consolidated balance sheets, and condensed consolidated statements of cash flows, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Holding, Inc. When we refer to the "WEC Merger," we are referring to the acquisition of Integrys Energy Group, Inc. by Wisconsin Energy Corporation, which was completed on June 29, 2015.

We prepare our financial statements in conformity with the rules and regulations of the SEC for Quarterly Reports on Form 10-Q and in accordance with GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2014. Financial results for an interim period may not give a true indication of results for the year.

Our balance sheet reflects the historical basis of our assets and liabilities as we did not elect pushdown accounting for the WEC Merger. This is consistent with how our financial statements are viewed by our regulators.

In management’s opinion, these unaudited financial statements include all adjustments necessary for a fair presentation of financial results. All adjustments are normal and recurring, unless otherwise noted. All intercompany transactions have been eliminated in consolidation.

Reclassifications

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

Statements of Income:

- Certain amortizations of regulatory deferrals were reclassified from operating and maintenance expense to cost of sales, depreciation and amortization expense, and miscellaneous income.

- Payroll taxes of $7.0 million and $16.4 million for the three and six months ended June 30, 2014, respectively, were reclassified from taxes other than income taxes to operating and maintenance expense. 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, operating and maintenance expense, and depreciation and amortization expense. The amounts reclassified to operating and maintenance expense were $3.4 million and $7.1 million for the three and six months ended June 30, 2014, respectively.

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

- Preferred stock dividends of subsidiary were reclassified to interest expense.

- Noncontrolling interest in subsidiaries was reclassified to miscellaneous income.

Balance Sheets:

- Current regulatory assets of $47.2 million and $71.7 million were reclassified to accounts receivable 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 energy costs refundable through rate adjustments and long-term regulatory liabilities, respectively.

- Noncontrolling interest in subsidiaries was reclassified to other long-term liabilities.

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Statements of Cash Flows:

- Preferred stock dividend payments were reclassified from financing activities to operating activities.
- Various other 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.

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 20, Segments of Business, 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.

Note 2—WEC Merger

On June 29, 2015, the WEC Merger was completed and we became a wholly owned subsidiary of WEC. Our shareholders received 1.128 shares of Wisconsin Energy 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.

In connection with the merger, we recognized after-tax merger-related costs of $38.4 million and $39.0 million during the three and six months ended June 30, 2015, respectively, and $4.1 million during the three and six months ended June 30, 2014. Included in the 2015 costs was $26.6 million of after-tax expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments. Our balance sheet as of June 30, 2015 included receivables from and payables to WEC of $27.3 million and $1.8 million, respectively. These balances primarily relate to the cash payments made for our outstanding stock-based compensation awards.

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 or its subsidiaries will first consider the extent to which existing intercompany resources can meet energy and capacity needs. Additionally, the ICC order included a base rate freeze for PGL and NSG effective for two years after the close of the merger. 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.

On July 24, 2015, the Citizens Utility Board, the City of Chicago, and the Illinois State Attorney General's office asked the ICC to rehear the merger order. The parties seek additional conditions previously requested during the approval process. The ICC has until August 13, 2015 to accept or deny the request. We believe the ICC's decision to approve the merger was correct and supported by sound principles and an extensive body of evidence.

Note 3—Dispositions

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 $331.8 million, which includes a working capital adjustment recorded during the first quarter of 2015. As part of the stock purchase agreement, we provided guarantees supporting the IES retail energy business. During the second quarter of 2015, the majority of these guarantees expired. See Note 12, Guarantees, for more information. We are providing certain administrative and operational services to Exelon during a transition period of up to 15 months after the sale date.

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The following table shows the components of discontinued operations related to the sale of IES's retail energy business recorded on the income statements. No activity was recorded for IES's retail energy business during the three months ended June 30, 2015.

	Three Months Ended	Six Months Ended June 30	
(Millions)	June 30, 2014	2015	2014
Revenues	$596.3	$—	$1,885.9
Cost of sales	(556.7)	—	(1,791.5)
Operating and maintenance expense	(27.7)	(1.2)	(60.5)
Depreciation and amortization expense	(0.8)	—	(1.5)
Property and revenue taxes	(0.7)	(0.2)	(1.1)
Goodwill impairment loss *	(6.7)	—	(6.7)
Transaction costs	(0.8)	—	(0.8)
Miscellaneous income	0.3	0.1	0.5
Interest expense	(0.2)	—	(0.4)
Income (loss) before taxes	3.0	(1.3)	23.9
(Provision) benefit for income taxes	(3.7)	0.5	(11.6)
Discontinued operations, net of tax	$(0.7)	$(0.8)	$12.3

* 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.

Dispositions

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 to TerraForm Power, Inc. (TerraForm) for $47.8 million. The purchase price is subject to adjustments for working capital. 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 transaction costs of $0.9 million. The results of operations of these solar assets through the sale date remain in continuing operations. 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.

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

	As of the Closing Date	Held for Sale at
(Millions)	in June 2015	December 31, 2014
Cash and cash equivalents	$0.3	$—
Accounts receivable	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

Other States Segment – Sale of UPPCO

In August 2014, we sold all of the common stock of UPPCO to Balfour Beatty Infrastructure Partners LP for $336.7 million. Following the sale, we are providing certain administrative and operational services to UPPCO during a transition period of 18 to 30 months.

Note 4—Cash and Cash Equivalents

Short-term investments with an original maturity of three months or less are reported as cash equivalents.

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Continuing Operations

Significant noncash transactions related to continuing operations were:

	Six Months Ended June 30	
(Millions)	2015	2014
Construction costs funded through accounts payable	$139.5	$123.3
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	—
Equity issued for employee stock ownership plan	—	1.7

At June 30, 2015, restricted cash of $30.2 million was recorded within other long-term assets on our balance sheet. This amount was held in the rabbi trust and represents a portion of the required funding for the rabbi trust that was triggered by the announcement of the WEC Merger. See Note 2, WEC Merger, for more information about the merger. See Note 13, Employee Benefit Plans, for more information on the rabbi trust funding requirements.

Discontinued Operations

Significant noncash transactions and other information related to discontinued operations were:

	Six Months Ended June 30	
(Millions)	2015	2014
Operating Activities		
Deferred income taxes and investment tax credits, net	$—	$15.5
Depreciation and amortization expense	—	1.6
Other	1.3	(3.1)

Note 5—Investment in ATC

We own approximately 34% of ATC, a for-profit, transmission-only company regulated by FERC.

The following table shows changes to our investment in ATC:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2015	2014	2015	2014
Balance at the beginning of period	$541.8	$517.6	$536.7	$508.4
Add: Earnings from equity method investment	22.4	23.0	39.4	45.5
Add: Capital contributions	1.7	5.1	3.4	10.2
Less: Dividends received	13.9	18.4	27.5	36.8
Balance at the end of period	$552.0	$527.3	$552.0	$527.3

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2015	2014	2015	2014
Income statement data				
Revenues	$165.1	$160.0	$317.5	$323.3
Operating expenses	80.3	74.4	160.3	153.0
Other expense	24.2	21.9	48.6	43.5
Net income	$60.6	$63.7	$108.6	$126.8

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(Millions)	June 30, 2015	December 31, 2014
Balance sheet data		
Current assets	$78.1	$66.4
Noncurrent assets	3,835.2	3,728.7
Total assets	$3,913.3	$3,795.1
Current liabilities	$255.7	$313.1
Long-term debt	1,800.0	1,701.0
Other noncurrent liabilities	197.7	163.8
Shareholders' equity	1,659.9	1,617.2
Total liabilities and shareholders' equity	$3,913.3	$3,795.1

Note 6—Inventories

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. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. The amounts were as follows at June 30, 2015:

		June 30, 2015	
(Millions)	Balance Sheet Presentation	PGL	NSG
Temporary LIFO liquidation debit	Other current assets	$21.0	$—
Temporary LIFO liquidation credit	Other current liabilities	—	5.2

Due to seasonality requirements, PGL and NSG expect these interim reductions in LIFO layers to be replenished by year end.

Note 7—Goodwill and Other Intangible Assets

We had no changes to the carrying amount of goodwill during the six months ended June 30, 2015, and 2014.

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 the balance sheets.

	June 30, 2015			December 31, 2014		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets (1)	$27.1	$(11.6)	$15.5	$34.9	$(11.9)	$23.0
Unamortized intangible assets (2)	10.7	—	10.7	10.2	—	10.2
Total intangible assets	$37.8	$(11.6)	$26.2	$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 the Fox Energy Center. The remaining weighted-average amortization period for our amortized intangible assets at June 30, 2015, was approximately five years.

(2) Consists primarily of trade names.

Note 8—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	June 30, 2015	December 31, 2014
Commercial paper	$314.4 *	$317.6
Average interest rate on commercial paper outstanding	0.37 %	0.36 %

*Maturity dates ranged from July 1, 2015, through July 14, 2015.

Our average amount of commercial paper borrowings based on daily outstanding balances during the six months ended June 30, 2015, and 2014, was $165.3 million and $215.6 million, respectively.

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We manage our liquidity by maintaining adequate external financing commitments. 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:

(Millions)	Maturity	June 30, 2015	December 31, 2014
Revolving credit facility (Integrys Holding)	06/13/2017	$285.0	$285.0
Revolving credit facility (Integrys Holding)	05/08/2019	265.0	465.0
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (WPS)	05/08/2019	135.0	135.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0
Total short-term credit capacity		$1,050.0	$1,250.0
Less:			
Letters of credit issued inside credit facilities		$0.7	$3.4
Commercial paper outstanding		314.4	317.6
Available capacity under existing agreements		$734.9	$929.0

Note 9—Long-Term Debt

(Millions)	June 30, 2015	December 31, 2014
WPS	$1,175.1	$1,175.1
PGL [(1)]	850.0	850.0
NSG	82.0	82.0
Integrys Holding	974.8	974.8
Total	3,081.9	3,081.9
Unamortized discount on debt	(0.6)	(0.6)
Total debt	3,081.3	3,081.3
Less current portion [(2)]	180.0	125.0
Total long-term debt	$2,901.3	$2,956.3

(1) On August 1, 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.

(2) In July 2015, we offered to buy back $55.0 million of 8.00% Senior Notes due June 1, 2016. The $55.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at June 30, 2015.

Note 10—Income Taxes

We calculate our interim period provision for, or benefit from income taxes based on our projected annual effective tax rate as adjusted for certain discrete items.

The table below shows our effective tax rates attributable to continuing operations:

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Effective tax rate	46.6 %	36.0 %	36.9 %	36.9 %

Our effective tax rate normally differs from the federal statutory tax rate of 35% due to additional provision for multistate income tax obligations. Other significant items that had an impact on our effective tax rates are noted below.

Our effective tax rate for the three months ended June 30, 2015 was higher than the 35% federal statutory rate primarily due to the accelerated recognition of unamortized investment tax credits driven by the sale of solar assets at PDL. This increased our benefit from income taxes due to a pre-tax loss for the quarter. No other items had a significant impact on our effective tax rates for the three and six months ended June 30, 2015 and 2014.

During the three and six months ended June 30, 2015, there was not a significant change in our liability for unrecognized tax benefits.

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Note 11—Commitments and Contingencies

(a) Unconditional Purchase Obligations and Purchase Order Commitments

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

The following table shows our minimum future commitments related to these purchase obligations as of June 30, 2015, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Year Contracts Extend Through	Total Amounts Committed	2015	2016	2017	2018	2019	Later Years
Wisconsin Operations								
Natural gas supply and transportation	2024	$218.9	$20.7	$43.8	$42.9	$42.4	$27.1	$42.0
Electric								
Purchased power	2029	816.3	61.4	78.9	54.1	56.8	58.1	507.0
Coal supply and transportation	2019	154.0	35.6	39.0	34.9	33.4	11.1	—
Illinois Operations								
Natural gas supply and transportation	2022	$191.3	$39.5	$76.7	$49.2	$14.1	$4.0	$7.8
Other States Operations								
Natural gas supply and transportation	2028	$215.5	$26.2	$52.9	$43.4	$23.7	$21.2	$48.1
Total		$1,596.0	$183.4	$291.3	$224.5	$170.4	$121.5	$604.9

(b) Environmental Matters

Air Permitting Violation Claims

Weston and Pulliam Clean Air Act (CAA) Issues:
In November 2009, the EPA issued a Notice of Violation (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 reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the U.S. District Court (Court) in March 2013, after a public comment period. The final Consent Decree includes:

- the installation of emission control technology, including ReACT™, at 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 2014 and 2015 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. We also believe that additional prudently incurred costs expected after 2015 will be recoverable from customers based on past precedent with the PSCW.

The majority of the beneficial environmental projects proposed by WPS have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

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 June 30, 2015. It is unknown whether the Sierra Club will take further action in the future.

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Columbia and Edgewater CAA Issues:
In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, WP&L, and Madison Gas and Electric reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. 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.

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.

We believe that significant costs prudently incurred as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty, will be recoverable from customers.

All of the beneficial environmental projects proposed by WPS have been approved by the EPA. Amounts have been accrued and recorded to regulatory assets, excluding costs associated with capital projects.

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, WPS also requested a modification to the construction permit for Weston 4 to remove the mercury Best Available Control Technology (BACT) emission limit requirement. This permit request was denied by the WDNR, and WPS challenged this issue as well. At WPS's request, the permit was modified to resolve several of the petition issues. Those issues have now been voluntarily dismissed from the case, while a new permit change was challenged and added to the case. The administrative law judge (ALJ) dismissed some of the petition issues relating to the averaging period and monitoring issues.

In May 2014, the WDNR issued an 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 nitrogen oxide emissions from the Weston 4 auxiliary boiler. In June 2015, the WDNR issued an NOV to WPS alleging that WPS failed to comply with mercury reporting requirements related to challenged matters in the 2013 Weston Title V permit. The ALJ denied WPS's request to issue a stay or confirm that a statutory stay applies to the requirements identified in the NOV. The contested case is proceeding and certain legal arguments are currently being addressed in the context of summary judgment motions. No hearing date has been set.

We do not expect these matters to have a material impact on our financial statements.

Air Quality

Mercury and Other Hazardous Air Pollutants:
In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), 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 mercury rules with the same compliance deadline that require a 90% reduction of mercury. 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 remains in effect pending action by the D.C Circuit Court of Appeals, which has the option to vacate the rule while the EPA completes its cost evaluation. If the rule is stayed or revoked, the Wisconsin Mercury Rule is likely to be the governing standard for the WPS units. At this time, it is too early to determine what effect, if any, this ruling will have on our compliance plans.

WPS initiated certain capital projects for its wholly owned plants to achieve the required reductions for MATS or the Wisconsin Mercury Rule. These capital costs are expected to be recovered in future rates.

Sulfur Dioxide:
The EPA issued a 1-Hour Sulfur Dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) that became effective in August 2010. In May 2014, the EPA issued the proposed Data Requirements Rule that would establish procedures and timelines for implementation of the standard. The proposed rule describes the EPA's plans for allowing the states to use either monitoring or modeling to make designations.

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As proposed, the rule affords state agencies latitude in rule implementation. States would have the option of modeling or monitoring to show attainment (subject to EPA approval for this selection). If the state chooses modeling and the sources in an area do not make reductions by 2017, and as a consequence the area is classified as nonattainment, then they would have to make emission reductions by 2023. Alternatively, if a state opted out of modeling and instead chose monitoring, 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 permitting constraints for area sources and for other new or existing sources in the area.

In March 2015, a Federal Court in the Northern District of California entered a consent decree relating to the implementation of the revised 1-Hour SO_2 standard that Sierra Club and EPA had agreed upon in May 2014. This consent decree has 1-Hour SO_2 implementation dates that are sooner than the proposed Data Requirements Rule. The EPA has not yet indicated how, in light of this consent decree, the Data Requirements Rule will be finalized.

We believe our fleet, with the exception of WPS's Pulliam plant, is well positioned to meet this regulation once it is finalized. The Pulliam plant is located in Brown County, which has been preliminarily determined to be in nonattainment with the standard based on monitoring data from 2012 through 2014. The WDNR has indicated that additional modeling and monitoring data will be required prior to final attainment designations being made in 2017 and 2020. We are currently working closely with the state of Wisconsin as they determine the attainment status of the areas and the effect, if any, on the Pulliam plant.

Land Quality

Coal Combustion Residuals (CCR) Rule:
In April 2015, the EPA published the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities final rule in the Federal Register. The final rule regulates the disposal of coal combustion byproducts, primarily fly ash and bottom ash, as a nonhazardous waste. The rules are intended to address risks related to groundwater impacts, catastrophic failures, and air emissions. There will be additional requirements for recordkeeping, groundwater monitoring, and structural integrity, including ongoing inspections and hazard assessments. There will also be more locational restrictions to protect wetlands and seismic impact zones. The rule will affect how WPS operates the Weston plant's bottom ash basins and an offsite landfill. However, we have landfill capacity that meets the rule requirements, if needed, for our coal combustion product sources. We do not expect the compliance costs to be significant because we currently have a program of beneficial utilization for most of our coal combustion byproducts and expect to recover these costs in future rates.

Water Quality

Clean Water Act Rule:
In August 2014, the EPA issued a final Clean Water Act rule under Section 316(b), which requires that the location, design, construction and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The rule became effective in October 2014 and applies to the Weston and Pulliam plants at WPS.

Facility owners must select from seven compliance options available to meet the impingement mortality (IM) reduction standard. BTA determinations must also be made to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. The rule requires state permitting agencies, including the WDNR, to make BTA determinations for IM and EM over the next several years, subject to EPA oversight, when facility permits are reissued. Based on our assessment, we believe that existing technologies at Weston Units 3 and 4 satisfy the IM and EM requirements by virtue of their existing cooling towers. In addition, it is expected that the

WDNR will determine that no modifications will be required at Weston Unit 2 due to low projected utilization. However, Pulliam Units 7 and 8 do not have the technologies to satisfy the IM and EM BTA requirements.

During 2015-18, we plan to complete studies to address the EM BTA requirements and evaluate the available IM options for Pulliam Units 7 and 8. We also expect limited studies to support WDNR BTA determinations to be conducted at the Weston facility. We cannot yet determine what, if any, intake structure or operational modifications will be required to meet the EM BTA requirements for Pulliam Units 7 and 8. We expect to recover any future compliance costs in future rates.

Manufactured Gas Plant Remediation

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

The future costs for detailed site investigation and future remediation 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, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

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We established the following reserves and regulatory assets related to manufactured gas plant sites:

(Millions)	June 30, 2015	December 31, 2014
Regulatory assets	$625.4	$634.3
Reserves for future remediation	576.0	579.7

Note 12—Guarantees

The following table shows our outstanding guarantees:

	Total Amounts Committed at	Expiration		
(Millions)	June 30, 2015	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$156.4	$83.4	$—	$73.0
Standby letters of credit (2)	1.2	1.1	0.1	—
Surety bonds (3)	32.2	32.2	—	—
Guarantees temporarily retained related to the sale of IES's retail energy business (4)	0.6	0.6	—	—
Other guarantees (5)	62.7	—	0.1	62.6
Total guarantees	$253.1	$117.3	$0.2	$135.6

(1) Consists of (a) $5.0 million and $6.0 million to support the business operations of WBS and PDL, respectively, and (b) $1.1 million, $109.3 million, and $35.0 million related to natural gas supply at ITF, MERC, and MGU, respectively. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts consist of standby letters of credit issued to support ITF, MERC, MGU, NSG, PDL, PGL, and WPS. These amounts are not reflected on our balance sheets.

(3) Primarily for the construction and operation of compressed natural gas 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) These guarantees were retained temporarily due to the sale of IES's retail energy business to Exelon Generation Company, LLC (Exelon). Exelon is contractually bound to reimburse us for any payments made under the outstanding guarantees. At June 30, 2015, these guarantees consisted of standby letters of credit. The liability related to these guarantees was insignificant. Our exposure under these guarantees related to open transactions at June 30, 2015, was $0.6 million.

(5) Consists of (a) $34.6 million to support PDL's future payment obligations related to its distributed solar generation projects; (b) $10.0 million related to the sale agreement for IES's Texas retail marketing business; (c) $11.2 million related to the performance of an operating and maintenance agreement by ITF; and (d) $6.9 million related to other indemnifications, primarily for workers compensation coverage. The amounts discussed in items (a), (c), and (d) are not reflected on our balance sheets. An insignificant liability was recorded for item (b) related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the

law.

Note 13—Employee Benefit Plans

Defined Benefit Plans

The following table shows the components of net periodic benefit cost (including amounts capitalized to our balance sheets) for our benefit plans:

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended June 30		Six Months Ended June 30		Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2015	2014	2015	2014	2015	2014	2015	2014
Service cost	$7.1	$5.9	$14.7	$12.5	$5.4	$4.8	$11.2	$10.7
Interest cost	16.7	19.3	33.7	39.0	5.1	5.2	10.4	12.3
Expected return on plan assets	(25.8)	(28.5)	(52.7)	(57.4)	(7.9)	(7.9)	(15.8)	(16.7)
Loss on plan settlement	0.7	0.9	1.2	0.9	—	—	—	—
Amortization of prior service cost (credit)	—	0.1	0.1	0.3	(2.5)	(2.8)	(5.1)	(4.1)
Amortization of net actuarial loss	12.1	8.6	22.6	17.0	0.8	0.8	1.9	1.5
Net periodic benefit cost	$10.8	$6.3	$19.6	$12.3	$0.9	$0.1	$2.6	$3.7

Prior service costs (credits) and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are recorded in accumulated other comprehensive income for our nonregulated entities and as net regulatory assets or liabilities for our regulated utilities.

In March 2014, we remeasured the obligations of certain other postretirement benefit 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.

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Rabbi Trust Funding Requirement

The Agreement and Plan of Merger entered into with Wisconsin Energy Corporation in June 2014 triggered the potential change in control provisions in the rabbi trust agreement. These provisions required the full funding of the present value of each participant's total benefit under the deferred compensation program and certain nonqualified pension plans. In 2015, a portion of the amounts contributed to the rabbi trust in 2014 and 2015 were used to fund participant's benefits under the deferred compensation program and certain nonqualified pension plans. See Note 2, WEC Merger, for more information on the merger.

Note 14—Stock-Based Compensation

Per the WEC Merger Agreement, immediately prior to completion of the merger, all of our outstanding stock-based compensation awards became fully vested and were canceled in exchange for the right to be paid out in cash to award recipients. The additional expense associated with the accelerated vesting of these awards totaled $22.7 million and was included with merger costs on the statement of income. See Note 2, WEC Merger, for more information regarding the merger.

The intrinsic values of the awards canceled 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 canceled was not significant. The actual tax benefit realized for the tax deductions from the payment of the canceled 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 for the three and six months ended June 30:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2015	2014	2015	2014
Stock options	$—	$0.5	$—	$0.8
Performance stock rights	2.7	9.2	3.3	9.7
Restricted share units	4.8	2.6	8.2	5.1
Nonemployee director deferred stock units	0.7	0.2	0.9	0.4
Total stock-based compensation expense	$8.2	$12.5	$12.4	$16.0
Deferred income tax benefit	$3.3	$5.0	$5.0	$6.4

A summary of the activity for our stock-based compensation awards for the six months ended June 30, 2015, is presented below:

	Stock Options	Performance Stock Rights	Restricted Stock Units
Outstanding at December 31, 2014	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)
Adjustment for performance stock rights distributed or canceled	N/A	169,379	N/A
Forfeited	—	—	(948)
Canceled due to WEC Merger	(63,325)	(367,565)	(493,614)
Outstanding at June 30, 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.

Note 15—Common Equity

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

Our ability to pay dividends or return capital to WEC 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.

The PSCW allows WPS to pay dividends on its common stock of no more than 103% of the previous year’s common stock dividend. WPS may return capital to us if its average financial common equity ratio is at least 51% on a calendar-year basis. WPS must obtain PSCW approval if a return of

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capital would cause its average financial common equity ratio to fall below this level. Our right to receive dividends on the common stock of WPS is also subject to the prior rights of WPS's preferred shareholders and to provisions in WPS's restated articles of incorporation, which limit the amount of common stock dividends that WPS may pay if its common stock and common stock surplus accounts constitute less than 25% of its total capitalization.

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.

PGL and WPS have short-term debt obligations containing financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%.

As of June 30, 2015, total restricted net assets of consolidated subsidiaries were $1,893.8 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $166.7 million at June 30, 2015.

We also have short-term and 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%. At June 30, 2015, these covenants did not restrict our retained earnings or the payment of any dividends.

We have the option to defer interest payments on our outstanding 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.

Except for the restrictions described above and subject to applicable law, we do not have any other significant dividend restrictions.

Note 16—Accumulated Other Comprehensive Loss

The following tables show the changes, net of tax, to our accumulated other comprehensive loss:

	Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
(Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at the beginning of period	$(3.1)	$(23.7)	$(26.8)	$(3.2)	$(24.4)	$(27.6)
Other comprehensive income before reclassifications	—	0.7	0.7	—	0.7	0.7
Amounts reclassified out of accumulated other comprehensive loss	0.2	0.9	1.1	0.3	1.6	1.9
Net current period other comprehensive income	0.2	1.6	1.8	0.3	2.3	2.6
Balance at the end of period	$(2.9)	$(22.1)	$(25.0)	$(2.9)	$(22.1)	$(25.0)

	Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
(Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive

			Loss			Loss
Balance at the beginning of period	$(3.7)	$(19.9)	$(23.6)	$(3.1)	$(20.1)	$(23.2)
Other comprehensive loss before reclassifications	—	—	—	—	(0.1)	(0.1)
Amounts reclassified out of accumulated other comprehensive loss	0.2	0.5	0.7	(0.4)	0.8	0.4
Net current period other comprehensive income (loss)	0.2	0.5	0.7	(0.4)	0.7	0.3
Balance at the end of period	$(3.5)	$(19.4)	$(22.9)	$(3.5)	$(19.4)	$(22.9)

Note 17—Risk Management Activities

Our derivatives include natural gas purchase contracts, coal purchase contracts, financial derivative contracts, and financial transmission rights (FTRs). None of these derivatives are designated as hedges for accounting purposes. We use financial derivative contracts to manage the risks associated with the market price volatility of natural gas supply costs, coal transportation costs, and the cost of gasoline and diesel fuel used by utility vehicles. We use FTRs to manage electric transmission congestion costs in the MISO market.

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The following tables show our assets and liabilities from risk management activities:

(Millions)	Balance Sheet Presentation *	June 30, 2015 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Natural gas contracts	Other current	$2.6	$19.5
Natural gas contracts	Other long-term	1.0	2.9
FTRs	Other current	4.1	—
Petroleum product contracts	Other current	—	0.9
Coal contracts	Other current	—	4.1
Coal contracts	Other long-term	—	2.1
	Other current	6.7	24.5
	Other long-term	1.0	5.0
Total		$7.7	$29.5

* We classify assets and liabilities from risk management activities as current or long-term based on the maturities of the underlying contracts.

(Millions)	Balance Sheet Presentation *	December 31, 2014 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Natural gas contracts	Other current	$1.8	$37.3
Natural gas contracts	Other long-term	0.5	5.3
FTRs	Other current	2.2	0.3
Petroleum product contracts	Other current	—	2.7
Petroleum product contracts	Other long-term	—	0.1
Coal contracts	Other current	—	2.4
Coal contracts	Other long-term	—	1.0
	Other current	4.0	42.7
	Other long-term	0.5	6.4
Total		$4.5	$49.1

* We classify assets and liabilities from risk management activities as current or long-term based on the maturities of the underlying contracts.

The following tables show the potential effect on our financial position of netting arrangements for recognized derivative assets and liabilities:

(Millions)	June 30, 2015 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	$7.7	$3.0	$4.7
Derivative assets not subject to master netting or similar arrangements	—		—
Total risk management assets	$7.7		$4.7
Derivative liabilities subject to master netting or similar arrangements	$22.1	$4.5	$17.6

Derivative liabilities not subject to master netting or similar arrangements	7.4		7.4
Total risk management liabilities	$29.5		$25.0

(Millions)	December 31, 2014 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	$3.2	$1.3	$1.9
Derivative assets not subject to master netting or similar arrangements	1.3		1.3
Total risk management assets	$4.5		$3.2
Derivative liabilities subject to master netting or similar arrangements	$45.7	$8.8	$36.9
Derivative liabilities not subject to master netting or similar arrangements	3.4		3.4
Total risk management liabilities	$49.1		$40.3

Our master netting and similar arrangements have conditional rights of setoff that can be enforced under a variety of situations, including counterparty default or credit rating downgrade below investment grade. We have trade receivables and trade payables, subject to master netting or similar arrangements, that are not included in the above tables. These amounts may offset (or conditionally offset) the net amounts presented in the above tables.

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Financial collateral provided is restricted to the extent that it is required per the terms of the related agreements. The following table shows our cash collateral positions:

(Millions)	June 30, 2015	December 31, 2014
Cash collateral provided to others: *		
Related to contracts under master netting or similar arrangements	$19.0	$11.6
Other	1.1	1.1

*Cash collateral provided to others is reflected in other current assets on our balance sheets.

Certain of our derivative and nonderivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a liability position at June 30, 2015, and December 31, 2014, was $19.8 million and $31.3 million, respectively. At June 30, 2015, and December 31, 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 commodity instruments (including derivatives, nonderivatives, normal purchase and normal sales contracts, and applicable payables and receivables) had been triggered at June 30, 2015, and at December 31, 2014, we would have been required to post collateral of $18.6 million and $27.1 million, respectively.

The notional volumes of our outstanding derivative contracts were as follows:

	June 30, 2015		December 31, 2014	
(Millions)	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (therms)	774.7	N/A	1,860.0	N/A
FTRs (kilowatt-hours)	N/A	8,577.9	N/A	4,287.7
Petroleum products (barrels)	0.1	N/A	0.1	N/A
Coal (tons)	2.2	N/A	3.0	N/A

The table below shows the unrealized gains (losses) recorded related to our derivative contracts:

		Three Months Ended June 30		Six Months Ended June 30	
(Millions)	Financial Statement Presentation	2015	2014	2015	2014
Natural gas	Balance Sheet — Regulatory assets	11.9	(1.0)	22.2	(0.3)
Natural gas	Balance Sheet — Regulatory liabilities	0.8	(3.3)	(0.6)	(0.3)
Natural gas	Income Statement — Operating and maintenance expense	0.2	(0.1)	0.1	0.1
FTRs	Balance Sheet — Regulatory assets	(7.2)	(1.0)	(7.0)	(0.9)
FTRs	Balance Sheet — Regulatory liabilities	2.4	1.1	2.0	1.0
Petroleum	Balance Sheet — Regulatory assets	0.5	—	0.9	—
Petroleum	Income Statement — Operating and maintenance expense	0.6	0.1	1.0	0.1
Coal	Balance Sheet — Regulatory assets	0.6	(0.1)	(4.0)	0.5
Coal	Balance Sheet — Regulatory liabilities	—	0.9	—	2.5

Note 18—Fair Value

A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information.

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). 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.

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.

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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.

When possible, we base the valuations of our risk management assets and liabilities on quoted prices for identical assets 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. The primary reasons for a Level 3 classification are as follows:

- Financial contracts used to manage transmission congestion costs in the MISO market are valued using historical prices.
- The valuations for certain physical coal contracts are based on significant assumptions made to extrapolate prices from the last observable period through the end of the transaction term.
- Certain natural gas contracts are valued using internally-developed inputs due to the absence of available market data for certain locations.

We have established risk oversight committees whose primary responsibility includes directly or indirectly ensuring that all valuation methods are applied in accordance with predefined policies. The development and maintenance of our forward price curves has been assigned to our risk management department. This department is separate and distinct from any of the supply functions within the organization. To validate the reasonableness of our fair value inputs, our risk management department compares changes in valuation and researches any significant differences in order to determine the underlying cause. Changes to the fair value inputs are made if necessary.

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

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

	June 30, 2015			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Natural gas contracts	$1.4	$2.2	$—	$3.6
Financial transmission rights (FTRs)	—	—	4.1	4.1
Total Risk Management Assets	$1.4	$2.2	$4.1	$7.7
Investment in exchange-traded funds	$107.5	$—	$—	$107.5
Liabilities				
Risk Management Liabilities				
Natural gas contracts	$1.4	$21.0	$—	$22.4
Petroleum product contracts	0.9	—	—	0.9
Coal contracts	—	0.8	5.4	6.2

Total Risk Management Liabilities	$2.3	$21.8	$5.4	$29.5

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	December 31, 2014			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Natural gas contracts	$—	$2.3	$—	$2.3
FTRs	—	—	2.2	2.2
Total Risk Management Assets	$—	$2.3	$2.2	$4.5
Investment in exchange-traded funds	$102.4	$—	$—	$102.4
Liabilities				
Risk Management Liabilities				
Natural gas contracts	$4.8	$31.2	$6.6	$42.6
FTRs	—	—	0.3	0.3
Petroleum product contracts	2.8	—	—	2.8
Coal contracts	—	1.2	2.2	3.4
Total Risk Management Liabilities	$7.6	$32.4	$9.1	$49.1

The risk management 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 market. See Note 17, Risk Management Activities, for more information.

There were no transfers between the levels of the fair value hierarchy during the three or six months ended June 30, 2015, and 2014.

The amounts listed in the table below represent the range of unobservable inputs used in the valuations that individually had a significant impact on the fair value determination and caused a derivative to be classified as Level 3 at June 30, 2015:

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
FTRs	$ 4.1	$ —	Market-based	Forward market prices ($/megawatt-month) [1]	$172.71
Coal contracts	—	5.4	Market-based	Forward market prices ($/ton) [2]	$9.86 – $13.23

(1) Represents forward market prices developed using historical cleared pricing data from MISO.

(2) Represents third-party forward market pricing.

Significant changes in historical settlement prices or forward coal prices would result in a directionally similar significant change in fair value.

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The following tables set forth a reconciliation of changes in the fair value of items categorized as Level 3 measurements:

Three Months Ended June 30, 2015

(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$0.6	$(6.2)	$(5.6)
Net realized losses included in earnings	(1.2)	—	(1.2)
Net unrealized (losses) gains recorded as regulatory assets or liabilities	(4.8)	0.3	(4.5)
Purchases	9.8	—	9.8
Settlements	(0.3)	0.5	0.2
Balance at the end of the period	$4.1	$(5.4)	$(1.3)

Three Months Ended June 30, 2014

(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$0.5	$0.3	$0.8
Net realized gains included in earnings	0.1	—	0.1
Net unrealized gains recorded as regulatory assets or liabilities	0.1	0.8	0.9
Purchases	4.4	—	4.4
Settlements	(1.1)	(0.2)	(1.3)
Balance at the end of the period	$4.0	$0.9	$4.9

Six Months Ended June 30, 2015

(Millions)	Natural Gas Contracts	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$(6.6)	$1.9	$(2.2)	$(6.9)
Net realized losses included in earnings	—	(2.4)	—	(2.4)
Net unrealized losses recorded as regulatory assets or liabilities	—	(5.0)	(4.0)	(9.0)
Purchases	—	9.8	—	9.8
Settlements	6.6	(0.2)	0.8	7.2
Balance at the end of the period	$—	$4.1	$(5.4)	$(1.3)

Six Months Ended June 30, 2014

(Millions)	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$1.2	$(2.5)	$(1.3)
Net realized gains included in earnings	0.8	—	0.8
Net unrealized gains recorded as regulatory assets or liabilities	0.1	3.0	3.1
Purchases	4.3	—	4.3
Settlements	(2.4)	0.4	(2.0)
Balance at the end of the period	$4.0	$0.9	$4.9

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 statements of income.

Fair Value of Financial Instruments

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

	June 30, 2015		December 31, 2014	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,081.3	$3,112.9	$3,081.3	$3,271.4
Preferred stock of subsidiary	51.1	53.1	51.1	51.8

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy.

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Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, and outstanding commercial paper, the carrying amount for each of these items approximates fair value.

Note 19—Regulatory Environment

Wisconsin

2016 Rate Case

In April 2015, WPS filed an application with the PSCW to increase retail electric rates $94.1 million and increase retail natural gas rates $9.4 million, with rates expected to be effective January 1, 2016. WPS's request reflects a 10.20% return on common equity and a target common equity ratio of 50.52% in WPS's regulatory capital structure. The proposed retail electric rate increase is primarily driven by the 2016 expected completion of the ReACT™ emission control technology at Weston 3, the System Modernization and Reliability Project, and technology upgrades at the Fox Energy Center. Also included are increases in expenses for electric transmission, customer service, other operating and maintenance, and general inflation. The proposed retail natural gas rate increase is driven by higher operating and maintenance costs, general inflation, and an increase in the amount of outstanding equity supporting construction projects.

In May 2015, WPS filed a revised application with the PSCW adjusting its requested retail electric rate increase to $96.9 million and its requested retail natural gas rate increase to $9.1 million. The revised requests are primarily driven by revisions to retail electric and natural gas revenues and employee benefit costs.

2015 Rates

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% return on common equity. The order also included a common equity ratio of 50.28% in WPS's regulatory capital structure. 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.

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 include approximately $9.0 million of lower refunds to customers related to decoupling over-collections. In 2015 rates, WPS is refunding 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 5 and 6 and Weston 1 starting with the actual retirement date in 2015 and concluding by 2023. See Note 11, 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. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a two percent 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 is refunding 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 Rates

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% return on common equity. The order also included a common equity ratio of 50.14% in WPS's regulatory capital structure. 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, 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. 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 11, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its decoupling mechanism, beginning January 1, 2014.

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Michigan

2016 MGU Rate Case

In June 2015, MGU filed an application with the MPSC to increase retail natural gas rates $6.7 million, with rates expected to be effective January 1, 2016. MGU's request reflects a 10.50% return on common equity and a target common equity ratio of 50.40% in MGU's regulatory capital structure. The proposed retail natural gas rate increase is driven by upgrades to MGU's natural gas transmission and distribution systems as well as a higher cost of capital. Also included are increases in costs for new employees, natural gas main maintenance, stand-by employee agreements, new customer service functions, and general inflation. MGU is requesting authority from the MPSC to continue the use of its currently authorized decoupling mechanism.

2015 WPS Rates

In April 2015, the MPSC issued a final written order for WPS, effective April 24, 2015, approving a settlement agreement between WPS and all parties. 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 10.20% return on common equity and a target common equity ratio of 50.48% in WPS's regulatory capital structure. 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 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 5 and 6 and Weston 1 starting with the actual retirement date in 2015 and concluding by 2023. Lastly, WPS will not seek to increase retail electric base rates prior to January 1, 2018.

2014 MGU Rates

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 reflected a 10.25% return on common equity and a common equity ratio of 48.62% in MGU's regulatory capital structure. 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.

Illinois

2015 Rates

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% return on common equity and a common equity ratio of 50.33% in PGL's regulatory capital structure. The rates for NSG reflect a 9.05% return on common equity and a common equity ratio of 50.48% in NSG's regulatory capital structure. The rate orders allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, PGL plans to recover 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 Attorney General 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 (formerly Senate Bill 2266), 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. The rider became effective on January 1, 2014.

2013 Rates Amended in 2014

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. 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

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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 Illinois Attorney General and Citizens Utility Board each filed an appeal with the Illinois Appellate Court. In April 2015, the Citizens Utility Board appeal was withdrawn, and, in May 2015, the Illinois Appellate Court dismissed the appeal from the Illinois Attorney General.

Minnesota

2014 Rates

In October 2014, the MPUC issued a final written order, effective April 1, 2015. The order authorized a retail natural gas rate increase of $7.6 million. The rates reflect a 9.35% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure. 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 expects to refund $4.7 million to customers in 2015, of which $3.5 million was refunded during the first half of 2015.

Note 20—Segments of Business

We reorganized our business segments during the second quarter of 2015 to reflect our new internal organization and management structure. We use net income to measure segment profitability and allocate resources to our businesses. All prior period amounts impacted by this change were reclassified to conform to the new presentation. At June 30, 2015, we reported five segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility and nonutility operations of WPS.
- The Illinois segment includes the natural gas utility and nonutility operations of NSG and PGL.
- The Other States segment includes the natural gas utility and nonutility 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 3, Dispositions, for more information on the sale of UPPCO.
- The Electric Transmission Investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- The Corporate and Other segment includes the operations of the holding company, ITF, PDL, the PELLC holding company, and any nonutility activities at WBS, as well as the operations of IES's retail energy business prior to its sale in November 2014 to Exelon Generation Company, LLC. See Note 3, Dispositions, for more information on the sale of IES's retail energy business.

The tables below present information related to our reportable segments:

	Regulated Operations							
(Millions)	Wisconsin	Illinois	Other States	Electric Transmission Investment	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Three Months Ended June 30, 2015								
External revenues	$330.2	$218.6	$67.9	$ —	$616.7	$ 21.6	$ —	$638.3
	30.2	30.8	4.8	—	65.8	6.3	—	72.1

Depreciation and amortization expense								
Merger costs	—	—	—	—	—	59.3	—	59.3
Impairment loss on property, plant, and equipment at PDL	—	—	—	—	—	10.7	—	10.7
Gain on sale of certain PDL solar power generation plants	—	—	—	—	—	(5.2)	—	(5.2)
Equity in earnings of transmission affiliate	—	—	—	22.4	22.4	—	—	22.4
Miscellaneous income (expense)	4.3	0.2	—	—	4.5	(0.2)	(2.5)	1.8
Interest expense	14.5	9.9	2.7	—	27.1	15.4	(2.5)	40.0
Provision (benefit) for income taxes	13.0	3.6	0.6	8.9	26.1	(34.2)	—	(8.1)
Net income (loss)	21.0	4.7	0.9	13.5	40.1	(49.4)	—	(9.3)

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(Millions)	Regulated Operations Wisconsin	Illinois	Other States	Electric Transmission Investment	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Three Months Ended June 30, 2014								
External revenues	$353.1	$351.0	$106.5	$ —	$810.6	$ 26.5	$ —	$837.1
Intersegment revenues	5.8	—	—	—	5.8	—	(5.8)	—
Depreciation and amortization expense	29.0	28.4	6.6	—	64.0	8.8	—	72.8
Merger costs	—	—	—	—	—	5.9	—	5.9
Equity in earnings of transmission affiliate	—	—	—	23.0	23.0	—	—	23.0
Miscellaneous income (expense)	4.2	(0.5)	—	—	3.7	5.2	(3.1)	5.8
Interest expense	15.1	8.2	3.1	—	26.4	16.0	(3.1)	39.3
Provision (benefit) for income taxes	9.9	(3.8)	(2.2)	9.2	13.1	(8.6)	—	4.5
Net income (loss) from continuing operations	15.5	(5.4)	(2.6)	13.8	21.3	(13.3)	—	8.0
Discontinued operations	—	—	—	—	—	(0.8)	—	(0.8)
Net income (loss)	15.5	(5.4)	(2.6)	13.8	21.3	(14.1)	—	7.2

(Millions)	Regulated Operations Wisconsin	Illinois	Other States	Electric Transmission Investment	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Six Months Ended June 30, 2015								
External revenues	$755.3	$750.2	$250.4	$ —	$1,755.9	$ 45.9	$ —	$1,801.8
Depreciation and amortization expense	60.1	62.5	9.5	—	132.1	15.4	—	147.5
Merger costs	—	—	—	—	—	60.0	—	60.0
Impairment loss on property, plant, and equipment at PDL	—	—	—	—	—	10.7	—	10.7
Gain on sale of certain PDL solar power generation plants	—	—	—	—	—	(5.2)	—	(5.2)
Equity in earnings of transmission affiliate	—	—	—	39.4	39.4	—	—	39.4
Miscellaneous income	8.8	0.9	—	—	9.7	3.9	(4.5)	9.1
Interest expense	29.2	19.4	5.0	—	53.6	29.9	(4.5)	79.0
Provision (benefit) for income taxes	35.1	52.3	12.3	15.6	115.3	(44.4)	—	70.9
Net income (loss) from continuing operations	58.6	76.2	18.3	23.8	176.9	(55.9)	—	121.0
Discontinued operations	—	—	—	—	—	(0.8)	—	(0.8)
Net income (loss)	58.6	76.2	18.3	23.8	176.9	(56.7)	—	120.2

(Millions)	Regulated Operations Wisconsin	Illinois	Other States	Electric Transmission Investment	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Six Months Ended June 30, 2014								
External revenues	$903.7	$1,127.8	$399.7	$ —	$2,431.2	$ 44.2	$ —	$2,475.4
Intersegment revenues	11.2	—	—	—	11.2	—	(11.2)	—
Depreciation and amortization expense	57.4	56.4	13.1	—	126.9	17.3	—	144.2
Merger costs	—	—	—	—	—	5.9	—	5.9
Equity in earnings of transmission affiliate	—	—	—	45.5	45.5	—	—	45.5
Miscellaneous income (expense)	9.2	(0.2)	—	—	9.0	9.8	(6.5)	12.3
Interest expense	29.9	16.5	6.5	—	52.9	32.6	(6.5)	79.0
Provision (benefit) for income taxes	38.7	35.6	14.1	18.0	106.4	(20.0)	—	86.4
Net income (loss) from continuing operations	64.3	52.3	22.0	27.5	166.1	(18.6)	—	147.5
Discontinued operations	—	—	—	—	—	12.1	—	12.1
Net income (loss)	64.3	52.3	22.0	27.5	166.1	(6.5)	—	159.6

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Note 21—New Accounting Pronouncements

Recently Issued Accounting Guidance Not Yet Effective

In April 2015 the FASB issued ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs." The guidance requires debt issuance costs to be presented on the balance sheet as a reduction to the carrying value of the corresponding debt, rather than as an asset as it is currently presented. The standard requires retrospective application by restating each prior period presented in the financial statements. The guidance is effective for us for the reporting period ending March 31, 2016. We are currently evaluating the impact this guidance will have on our financial statements.

In May 2014 the FASB issued ASU 2014-09, "Revenue from Contracts with Customers." This ASU supersedes the requirements in the Revenue Recognition Topic of the FASB ASC and most industry-specific guidance throughout the ASC. The guidance is based on the principle that revenue is recognized when promised goods or services are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and cash flows from customer contracts. The guidance was originally effective for us for the reporting period ending March 31, 2017; however, in July 2015 the FASB decided to delay the effective date for one year. Companies can still elect to adopt the standard as of the original effective date. The standard requires either retrospective application by restating each prior period presented in the financial statements, or modified retrospective application by recording the cumulative effect of prior reporting periods to beginning retained earnings in the year that the standard becomes effective. We are currently evaluating the impact that the adoption of this standard will have on our financial statements.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2014.

SUMMARY

On June 29, 2015, the WEC Merger was completed and we became a wholly owned subsidiary of WEC. We are an energy holding company with natural gas and electric utility operations (serving customers in Illinois, Michigan, Minnesota, and Wisconsin), an approximate 34% equity ownership interest in ATC (a federally regulated electric transmission company), and nonregulated energy operations.

In the second quarter of 2015, we changed our reportable segments. See Note 20, Segments of Business, for more information

RESULTS OF OPERATIONS

Earnings Summary

(Millions)	Three Months Ended June 30 2015	2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	2014	Change in 2015 Over 2014
Wisconsin operations	$21.0	$15.5	35.5 %	$58.6	$64.3	(8.9)%
Illinois operations	4.7	(5.4)	N/A	76.2	52.3	45.7 %
Other states operations	0.9	(2.6)	N/A	18.3	22.0	(16.8)%
Electric transmission investment	13.5	13.8	(2.2)%	23.8	27.5	(13.5)%
Corporate and other operations	(49.4)	(14.1)	250.4 %	(56.7)	(6.5)	772.3 %
Net income	$(9.3)	$7.2	N/A	$120.2	$159.6	(24.7)%

Second Quarter 2015 Compared with Second Quarter 2014

The $16.5 million decrease in our earnings was driven by:

- A $34.3 million after-tax increase in merger-related costs. Included in the 2015 costs was $26.6 million of after-tax expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

- A $6.4 million after-tax impairment loss recorded on property, plant, and equipment at PDL in 2015.

- An approximate $2.0 million after-tax net decrease in margins at our existing utilities due to variances related to sales volumes, net of decoupling. The decrease was driven by lower use per residential customer at our Wisconsin segment and warmer weather in the second quarter of 2015.

- An approximate $2.0 million after-tax decrease in earnings due to the sale of UPPCO in August 2014. See Note 3, Dispositions, for more information.

These decreases in earnings were partially offset by:

- The approximate $14.0 million after-tax positive impact of rate orders at our utilities.

- A $9.1 million after-tax decrease in operating expenses at our existing utilities, excluding items directly offset in margins, driven by lower repairs and maintenance expense.

- A $5.5 million after-tax gain on the sale of certain PDL solar power generation plants in 2015.

Six Months 2015 Compared with Six Months 2014

The $39.4 million decrease in our earnings was driven by:

- A $34.9 million after-tax increase in merger-related costs. Included in the 2015 costs was $26.6 million of after-tax expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

- A $12.9 million after-tax decrease in earnings from discontinued operations driven by the sale of IES's retail energy business in November 2014. See Note 3, Dispositions, for more information.

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- An approximate $13.0 million after-tax decrease in margins at our existing utilities due to variances related to sales volumes, net of decoupling, driven by warmer weather in 2015.

- An approximate $6.0 million after-tax decrease in earnings due to the sale of UPPCO in August 2014. See Note 3, Dispositions, for more information.

- A $6.4 million after-tax impairment loss recorded on property, plant, and equipment at PDL in 2015.

- A $3.7 million after-tax decrease in earnings from our approximate 34% ownership interest in ATC. ATC's earnings for the six months ended June 30, 2015 included a reserve for an anticipated refund to customers related to a complaint filed with the FERC requesting a lower return on equity for certain transmission owners.

These decreases in earnings were partially offset by:

- A $19.0 million after-tax decrease in operating expenses at our existing utilities, excluding items directly offset in margins, driven by lower repairs and maintenance expense.

- The approximate $15.0 million after-tax positive net impact of rate orders at our utilities.

- A $5.5 million after-tax gain on the sale of certain PDL solar power generation plants in 2015.

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Wisconsin Segment Operations

(Millions, except degree days)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014	Change in 2015 Over 2014
Revenues	$330.2	$358.9	(8.0)%	$755.3	$914.9	(17.4)%
Cost of sales	120.4	147.7	(18.5)%	321.0	450.7	(28.8)%
Margins	209.8	211.2	(0.7)%	434.3	464.2	(6.4)%
Operating and maintenance expense	125.1	135.4	(7.6)%	239.6	262.5	(8.7)%
Depreciation and amortization expense	30.2	29.0	4.1%	60.1	57.4	4.7%
Property and revenue taxes	10.3	10.5	(1.9)%	20.5	20.6	(0.5)%
Operating income	44.2	36.3	21.8%	114.1	123.7	(7.8)%
Miscellaneous income	4.3	4.2	2.4%	8.8	9.2	(4.3)%
Interest expense	14.5	15.1	(4.0)%	29.2	29.9	(2.3)%
Other expense	(10.2)	(10.9)	(6.4)%	(20.4)	(20.7)	(1.4)%
Income before taxes	$34.0	$25.4	33.9%	$93.7	$103.0	(9.0)%
Retail throughput in therms						
Residential	33.1	39.9	(17.0)%	161.2	181.8	(11.3)%
Commercial and industrial	20.5	24.9	(17.7)%	94.7	112.1	(15.5)%
Other	8.2	4.7	74.5%	15.4	14.6	5.5%
Total retail throughput in therms	61.8	69.5	(11.1)%	271.3	308.5	(12.1)%
Transport throughput in therms						
Commercial and industrial	78.9	79.8	(1.1)%	192.7	200.6	(3.9)%
Total throughput in therms	140.7	149.3	(5.8)%	464.0	509.1	(8.9)%
Sales in kilowatt-hours						
Residential	588.5	627.5	(6.2)%	1,350.6	1,446.3	(6.6)%
Commercial and industrial	1,977.9	1,969.6	0.4%	3,947.0	3,926.2	0.5%
Wholesale	629.1	665.3	(5.4)%	1,264.6	1,331.5	(5.0)%
Opportunity sales	124.1	156.0	(20.4)%	426.1	269.5	58.1%
Other	6.3	6.4	(1.6)%	15.5	15.8	(1.9)%
Total sales in kilowatt-hours	3,325.9	3,424.8	(2.9)%	7,003.8	6,989.3	0.2%
Weather *						
Actual heating degree days	840	1,020	(17.6)%	4,786	5,535	(13.5)%
Normal heating degree days	981	975	0.6%	4,643	4,621	0.5%
Actual cooling degree days	98	109	(10.1)%	98	109	(10.1)%
Normal cooling degree days	137	141	(2.8)%	137	141	(2.8)%

* Normal heating and cooling degree days are based on a 20-year average of monthly temperatures from the Green Bay Weather Station.

Second Quarter 2015 Compared with Second Quarter 2014

Electric Margins

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric margins provide a more meaningful basis for evaluating electric operations than electric operating revenues. To the extent changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in operating revenues.

Electric margins decreased $3.1 million, driven by:

- An approximate $5.0 million decrease in margins related to sales volume variances. Margins from residential customers decreased, driven by lower use per customer and warmer weather in the second quarter of 2015.

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- A partially offsetting approximate $2.0 million increase in margins related to rates, driven by:

An increase of approximately $3.0 million related to fuel and purchased power cost over-collections as compared with approved rates in 2015, as opposed to under-collections as compared with approved rates in 2014. Under the fuel rule, WPS can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

This increase was partially offset by a decrease in margins of approximately $1.0 million as a result of the PSCW rate order and rate design, effective January 1, 2015. Although the PSCW approved an electric rate increase, the majority of the increase related to higher costs of fuel for electric generation, which has no impact on margins. See Note 19, Regulatory Environment, for more information.

Natural Gas Margins

Natural gas margins are defined as natural gas operating revenues less purchased natural gas costs. Management believes that natural gas margins provide a more meaningful basis for evaluating natural gas operations than natural gas revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 31% and 39% decrease in the average per-unit cost of natural gas sold during the three and six months ended June 30, 2015, which had no impact on margins.

Natural gas margins increased $1.7 million, driven by:

- An approximate $4.0 million increase in margins related to the PSCW rate order, effective January 1, 2015. Although the PSCW approved a natural gas rate decrease, the increase in margins in the second quarter of 2015 was driven by rate design changes. The approved rate design increased fixed charges but lowered volumetric charges to customers to better match the fixed costs of providing service. As a result, this rate design provides for higher cost recovery in periods of low sales volumes. Some of this impact is expected to reverse in future quarters with changes in sales volumes. See Note 19, Regulatory Environment, for more information.

- A partially offsetting $2.0 million decrease in margins related to sales volume variances. Margins from residential customers decreased, driven by warmer weather and lower use per customer in the second quarter of 2015.

Operating Income

Operating income at the Wisconsin segment increased $7.9 million. This increase was driven by a $9.3 million decrease in operating expenses, partially offset by the combined $1.4 million net decrease in electric and natural gas margins discussed above.

The decrease in operating expenses was primarily due to a $13.0 million decrease in maintenance expense, primarily at the Fox Energy Center, Pulliam, and our jointly-owned plants in 2015. Maintenance costs were also lower in the second quarter of 2015 due to a planned major outage at the Weston plant in 2014. This decrease was partially offset by a $1.8 million increase in electric transmission expenses.

Six Months 2015 Compared with Six Months 2014

Electric Margins

Electric margins decreased $11.5 million, driven by:

- An approximate $10.0 million decrease in margins related to sales volume variances. Margins from residential customers decreased, driven by warmer weather and lower use per customer in 2015.

- An approximate $1.0 million decrease in margins related to rates.

Margins decreased approximately $7.0 million as a result of the PSCW rate order and rate design, effective January 1, 2015. Although the PSCW approved an electric rate increase, the majority of the increase related to higher costs of fuel for electric generation, which has no impact on margins. See Note 19, Regulatory Environment, for more information.

These decreases in margins were partially offset by an increase of approximately $6.0 million related to fuel and purchased power cost over-collections as compared with approved rates in 2015, as opposed to under-collections as compared with approved rates in 2014. Under the fuel rule, WPS can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

- An approximate $1.0 million decrease in wholesale margins driven by a reduction in sales volumes. Certain wholesale customers have provisions in their contracts which allow them to reduce the amount of energy we provide to them.

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Natural Gas Margins

Natural gas margins decreased $18.4 million, driven by:

- An approximate $12.0 million decrease in margins due to the PSCW rate order, effective January 1, 2015, including an approximate $3.0 million negative impact due to rate design changes. The approved rate design increased fixed charges but lowered volumetric charges to customers to better match the fixed costs of providing service. As a result, this rate design provides for lower cost recovery in periods of high sales volumes. Some of this impact is expected to reverse in future quarters with changes in sales volumes. See Note 19, Regulatory Environment, for more information.

- An approximate $7.0 million decrease in margins related to sales volume variances, driven by warmer weather in 2015.

Operating Income

Operating income at the Wisconsin segment decreased $9.6 million. This decrease was driven by the $29.9 million decrease in electric and gas margins discussed above, partially offset by a $20.3 million decrease in operating expenses.

The decrease in operating expenses was primarily due to:

- A $20.9 million decrease in maintenance expense, primarily due to planned major outages at the Pulliam 8 plant and Weston 4 plant in 2014, as well as lower maintenance at the Fox Energy Center and our jointly-owned plants in 2015.

- A $3.6 million decrease in asset usage charges from WBS.

These decreases were partially offset by:

- A $3.6 million increase in electric transmission expenses.

- A $2.7 million increase in depreciation and amortization expense, mainly due to the installation of scrubbers at the Columbia plant in April 2014.

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Illinois Segment Operations

(Millions, except degree days)	Three Months Ended June 30 2015	2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	2014	Change in 2015 Over 2014
Revenues	$218.6	$351.0	(37.7)%	$750.2	$1,127.8	(33.5)%
Cost of sales	53.4	187.7	(71.6)%	295.2	660.7	(55.3)%
Margins	165.2	163.3	1.2%	455.0	467.1	(2.6)%
Operating and maintenance expense	111.8	132.3	(15.5)%	236.3	298.7	(20.9)%
Depreciation and amortization expense	30.8	28.4	8.5%	62.5	56.4	10.8%
Property and revenue taxes	4.6	3.1	48.4%	9.2	7.4	24.3%
Operating income (loss)	18.0	(0.5)	N/A	147.0	104.6	40.5%
Miscellaneous income (expense)	0.2	(0.5)	N/A	0.9	(0.2)	N/A
Interest expense	9.9	8.2	20.7%	19.4	16.5	17.6%
Other expense	(9.7)	(8.7)	11.5%	(18.5)	(16.7)	10.8%
Income (loss) before taxes	$8.3	$(9.2)	N/A	$128.5	$87.9	46.2%
Retail throughput in therms						
Residential	116.6	141.8	(17.8)%	629.3	748.7	(15.9)%
Commercial and industrial	24.6	31.8	(22.6)%	131.7	159.5	(17.4)%
Total retail throughput in therms	141.2	173.6	(18.7)%	761.0	908.2	(16.2)%
Transport throughput in therms						
Residential	35.9	34.0	5.6%	169.2	154.2	9.7%
Commercial and industrial	111.9	117.9	(5.1)%	383.6	403.9	(5.0)%
Total transport throughput in therms	147.8	151.9	(2.7)%	552.8	558.1	(0.9)%
Total throughput in therms	289.0	325.5	(11.2)%	1,313.8	1,466.3	(10.4)%
Weather *						
Actual heating degree days	704	696	1.1%	4,294	4,566	(6.0)%
Normal heating degree days	703	718	(2.1)%	3,878	3,811	1.8%

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

Natural gas margins are defined as natural gas operating revenues less purchased natural gas costs. Management believes that natural gas margins provide a more meaningful basis for evaluating natural gas operations than natural gas revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 66% and 46% decrease in the average per-unit cost of natural gas sold during the three and six months ended June 30, 2015, respectively, which had no impact on margins.

Second Quarter 2015 Compared with Second Quarter 2014

Margins

Illinois segment margins increased $1.9 million, driven by:

- An approximate $17.0 million increase in margins due to rate orders. See Note 19, Regulatory Environment, for more information.

The rate increases at our Illinois utilities, effective January 28, 2015, and updated effective February 26, 2015, had an approximate $16.0 million positive impact on margins.

Increased revenues at PGL for its Qualifying Infrastructure Plant rider had an approximate $1.0 million positive impact on margins.

- This increase was partially offset by a $13.8 million decrease in margins related to certain riders. This decrease was offset by an equal decrease in operating expenses, resulting in no impact on earnings.

Our Illinois utilities recovered $5.9 million less from their customers through their bad debt rider mechanisms, driven by lower natural gas costs in 2015, and a decrease in sales volumes.

Our Illinois utilities recovered $4.8 million less from customers for energy efficiency programs in 2015.

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Our Illinois utilities recovered $3.1 million less from their customers for environmental cleanup costs at their former manufactured gas plant sites due to lower recovery rates driven by a decrease in remediation costs, net of insurance settlements received, and the impact of lower sales volumes. See Note 11, Commitments and Contingencies, for more information about the manufactured gas plant sites.

Operating Income

Operating income at the Illinois segment increased $18.5 million. The increase was due to a $16.6 million decrease in operating expenses and the $1.9 million increase in margins discussed above.

The decrease in operating expenses was driven by:

- A $14.9 million decrease in natural gas distribution costs at PGL, driven by reduced repair and maintenance activity.

- A $5.9 million decrease in bad debt expense, driven by lower natural gas costs in 2015 and a decrease in sales volumes. This decrease in bad debt expense had no impact on earnings since it was offset by lower rates through a rider mechanism, resulting in lower margins.

- A $4.7 million decrease in energy efficiency program expenses. For the majority of this decrease in expenses, margins decreased by an equal amount, resulting in no impact on earnings.

- A $3.1 million decrease driven by lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites. This decrease in expense was offset by a related decrease in margins, resulting in no impact on earnings.

These decreases were partially offset by:

- Accrued expense of $5.0 million at PGL for future contributions into the "Share the Warmth" program requested by the ICC as a condition for the approval of the WEC Merger. These costs will not be recovered from ratepayers.

- A $2.4 million increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the AMRP at PGL.

- A $2.4 million net increase in employee benefit costs partially driven by higher pension and postretirement costs as well as higher employee medical costs.

- A $1.5 million increase in property and revenue taxes, driven by the Illinois invested capital tax. This tax is based on an entity's equity and long-term debt balances.

Six Months 2015 Compared with Six Months 2014

Margins

Illinois segment margins decreased $12.1 million, driven by:

- A $47.3 million decrease in margins related to certain riders. This decrease was offset by an equal decrease in operating expenses, resulting in no impact on earnings.

Our Illinois utilities recovered $23.7 million less from customers for energy efficiency programs in 2015.

Our Illinois utilities recovered $14.3 million less from their customers through their bad debt rider mechanisms, driven by lower natural gas costs in 2015, and a decrease in sales volumes.

Our Illinois utilities recovered $9.3 million less from their customers for environmental cleanup costs at their former manufactured gas plant sites due to lower recovery rates driven by a decrease in remediation costs, net of insurance settlements received, and the impact of lower sales volumes. See Note 11, Commitments and Contingencies, for more information about the manufactured gas plant sites.

- An approximate $2.0 million decrease in margins from the combined effect of warmer weather period over period, lower weather-normalized volumes, and the partially offsetting impact of our decoupling mechanisms. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by decoupling mechanisms. See Note 19, Regulatory Environment, for more information on our decoupling mechanisms.

- These decreases were partially offset by an approximate $38.0 million increase in margins due to rate orders. See Note 19, Regulatory Environment, for more information.

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The rate increases at our Illinois utilities, effective January 28, 2015, and updated effective February 26, 2015, had an approximate $34.0 million positive impact on margins.

Increased revenues at PGL for its Qualifying Infrastructure Plant rider had an approximate $4.0 million positive impact on margins.

Operating Income

Operating income at the Illinois segment increased $42.4 million. The increase was driven by a $54.5 million decrease in operating expenses, partially offset by the $12.1 million decrease in margins discussed above.

The decrease in operating expenses was driven by:

- A $23.9 million net decrease in energy efficiency program expenses. For the majority of this decrease in expenses, margins decreased by an equal amount, resulting in no impact on earnings.

- A $19.9 million decrease in natural gas distribution costs at PGL, driven by reduced repair and maintenance activity.

- A $14.3 million decrease in bad debt expense, driven by lower natural gas costs in 2015 and a decrease in sales volumes. This decrease in bad debt expense had no impact on earnings since it was offset by lower rates through a rider mechanism, resulting in lower margins.

- A $9.3 million net decrease driven by lower amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. This decrease in expenses was offset by a related decrease in margins, resulting in no impact on earnings.

These decreases were partially offset by:

- A $6.1 million increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the AMRP at PGL.

- Accrued expense of $5.0 million at PGL for future contributions into the "Share the Warmth" program requested by the ICC as a condition for the approval of the WEC Merger. These costs will not be recovered from ratepayers.

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Other States Segment Operations

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 3, Dispositions, for more information.

(Millions, except degree days)	Three Months Ended June 30 2015	2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	2014	Change in 2015 Over 2014
Revenues	$67.9	$106.5	(36.2)%	$250.4	$399.7	(37.4)%
Cost of sales	30.0	52.1	(42.4)%	144.4	243.1	(40.6)%
Margins	37.9	54.4	(30.3)%	106.0	156.6	(32.3)%
Operating and maintenance expense	25.9	45.6	(43.2)%	54.8	93.1	(41.1)%
Depreciation and amortization expense	4.8	6.6	(27.3)%	9.5	13.1	(27.5)%
Property and revenue taxes	3.0	3.9	(23.1)%	6.1	7.8	(21.8)%
Operating income (loss)	4.2	(1.7)	N/A	35.6	42.6	(16.4)%
Interest expense	2.7	3.1	(12.9)%	5.0	6.5	(23.1)%
Income (loss) before taxes	$1.5	$(4.8)	N/A	$30.6	$36.1	(15.2)%
Retail throughput in therms						
Residential	38.2	40.8	(6.4)%	190.6	219.2	(13.0)%
Commercial and industrial	19.3	20.2	(4.5)%	93.8	106.6	(12.0)%
Other	4.4	4.9	(10.2)%	15.9	19.0	(16.3)%
Total retail throughput in therms	61.9	65.9	(6.1)%	300.3	344.8	(12.9)%
Transport throughput in therms						
Residential	2.7	3.4	(20.6)%	12.6	18.6	(32.3)%
Commercial and industrial	136.4	153.8	(11.3)%	351.2	365.9	(4.0)%
Total transport throughput in therms	139.1	157.2	(11.5)%	363.8	384.5	(5.4)%
Total throughput in therms	201.0	223.1	(9.9)%	664.1	729.3	(8.9)%
Weather *						
Average actual heating degree days	824	937	(12.1)%	4,710	5,245	(10.2)%
Average normal heating degree days	869	864	0.6%	4,427	4,376	1.2%

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

Utility margins are defined as operating revenues less fuel, purchased power, and natural gas costs. Management believes that utility margins provide a more meaningful basis for evaluating utility operations than utility operating revenues, since prudently incurred commodity costs are passed through to our customers in current rates. There was an approximate 27% and 26% decrease in the average per-unit cost of natural gas sold during the three and six months ended June 30, 2015, respectively, which had no impact on margins.

Second Quarter 2015 Compared with Second Quarter 2014

Margins

Other states segment margins decreased $16.5 million, driven by:

- An approximate $19.0 million decrease in margins related to the sale of UPPCO at the end of August 2014. See Note 3, Dispositions, for more information.
- A $4.2 million net decrease in margins due to a reduction in the amounts recovered from customers for energy efficiency programs at MERC and MGU. This decrease was offset by an equal decrease in operating expenses, resulting in no impact on earnings.
- Partially offsetting these decreases was an approximate $4.0 million increase in margins related to sales volume variances at MERC and MGU, net of the impacts of decoupling. The positive impact from higher weather-normalized sales volumes to retail customers was partially offset by the effect of warmer weather in 2015. Margins were sensitive to volume variances as MGU did not have decoupling in 2014, and not all volume variances are covered by decoupling.

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Operating Income

Operating income at the other states segment increased $5.9 million. The increase was driven by a $22.4 million decrease in operating expenses, partially offset by the $16.5 million decrease in margins discussed above.

The decrease in operating expenses was driven by:

- A $15.2 million decrease in operating expenses related to the sale of UPPCO at the end of August 2014. See Note 3, Dispositions, for more information.
- A $4.2 million net decrease in energy efficiency program expenses at MERC and MGU. This decrease was offset by an equal decrease in margins, resulting in no impact on earnings.
- A $3.7 million positive quarter-over-quarter impact from MERC's 2014 write down of a regulatory asset for conservation improvement program costs.

Six Months 2015 Compared with Six Months 2014

Margins

Other states segment margins decreased $50.6 million, driven by:

- An approximate $41.0 million decrease in margins related to the sale of UPPCO at the end of August 2014. See Note 3, Dispositions, for more information.
- A $9.6 million net decrease in margins due to a reduction in the amounts recovered from customers for energy efficiency programs at MERC and MGU. This decrease was offset by an equal decrease in operating expenses, resulting in no impact on earnings.
- An approximate $3.0 million decrease in margins related to sales volume variances at MERC and MGU, net of the impacts of decoupling. The decrease was driven by the warmer weather in 2015. Margins were sensitive to volume variances as MGU did not have decoupling in 2014, and not all volume variances are covered by decoupling.

Operating Income

Operating income at the other states utility segment decreased $7.0 million. The decrease was driven by the $50.6 million decrease in margins discussed above, partially offset by a $43.6 million decrease in operating expenses.

The decrease in operating expenses was driven by:

- A $29.8 million decrease in operating expenses related to the sale of UPPCO at the end of August 2014. See Note 3, Dispositions, for more information.
- A $9.6 million net decrease in energy efficiency program expenses at MERC and MGU. This decrease was offset by an equal decrease in margins, resulting in no impact on earnings.
- A $3.7 million positive period-over-period impact from MERC's 2014 write down of a regulatory asset for conservation improvement program costs.

Electric Transmission Investment Segment Operations

(Millions)	Three Months Ended June 30 2015	2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	2014	Change in 2015 Over 2014
Equity in earnings of transmission affiliate	$22.4	$23.0	(2.6)%	$39.4	$45.5	(13.4)%

Second Quarter 2015 Compared with Second Quarter 2014

Earnings from our approximate 34% ownership interest in ATC decreased $0.6 million. ATC's 2015 earnings included a reserve for an anticipated refund to customers related to a complaint filed with the FERC requesting a lower return on equity for certain transmission owners.

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Six Months 2015 Compared with Six Months 2014

Earnings from our approximate 34% ownership interest in ATC decreased $6.1 million. ATC's 2015 earnings included a reserve for an anticipated refund to customers related to a complaint filed with the FERC requesting a lower return on equity for certain transmission owners.

Corporate and Other Segment Operations

(Millions)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Change in 2015 Over 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014	Change in 2015 Over 2014
Operating loss	$(68.0)	$(11.1)	512.6 %	$(74.3)	$(15.8)	370.3 %
Other expense	(15.6)	(10.8)	44.4 %	(26.0)	(22.8)	14.0 %
Loss before taxes	$(83.6)	$(21.9)	281.7 %	$(100.3)	$(38.6)	159.8 %

Second Quarter 2015 Compared with Second Quarter 2014

Operating Loss

Operating loss at the corporate and other segment increased $56.9 million, driven by:

- A $53.4 million increase in merger-related costs. Included in the 2015 costs was $43.0 million of expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

- A $10.7 million impairment loss recorded on property, plant, and equipment at PDL in 2015.

These operating loss increases were partially offset by:

- A $5.2 million gain on the sale of certain PDL solar power generation plants in 2015.

- An approximate $3.0 million positive quarter-over-quarter impact from WBS costs previously charged to IES's retail energy business that were allocated to the corporate and other segment in 2014. This variance had no impact on our consolidated earnings as it was offset in the other segments.

Other Expense

Other expense at the corporate and other segment increased $4.8 million. The increase was primarily due to a $4.3 million unrealized loss recorded in 2015 on exchange-traded funds held in a rabbi trust at the holding company. The rabbi trust began investing in exchange-traded funds in July 2014.

Six Months 2015 Compared with Six Months 2014

Operating Loss

Operating loss at the corporate and other segment increased $58.5 million, driven by:

- A $54.1 million increase in merger-related costs. Included in the 2015 costs was $43.0 million of expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

- A $10.7 million impairment loss recorded on property, plant, and equipment at PDL in 2015.

- A $3.8 million decrease in WBS's return on capital charged to the utilities. This variance had no impact on our consolidated earnings as it was offset in the other segments.

These operating loss increases were partially offset by:

- A $5.2 million gain on the sale of certain PDL solar power generation plants in 2015.
- An approximate $5.0 million positive period-over-period impact from WBS costs previously charged to IES's retail energy business that were allocated to the corporate and other segment in 2014. This variance had no impact on our consolidated earnings as it was offset in the other segments.

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Other Expense

Other expense at the corporate and other segment increased $3.2 million. The increase was primarily due to a $3.8 million unrealized loss recorded in 2015 on exchange-traded funds held in a rabbi trust at the holding company. The rabbi trust began investing in exchange-traded funds in July 2014.

Provision for Income Taxes

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Effective tax rate	46.6 %	36.0 %	36.9 %	36.9 %

Second Quarter 2015 Compared with Second Quarter 2014

Our effective tax rate increased in the second quarter of 2015. This increase was primarily due to the accelerated recognition of unamortized investment tax credits driven by the sale of solar assets at PDL. This increased our benefit from income taxes due to a pre-tax loss for the quarter.

Six Months 2015 Compared with Six Months 2014

There was no material change in our effective tax rate period over period.

Discontinued Operations

	Three Months Ended June 30		Change in 2015 Over	Six Months Ended June 30		Change in 2015 Over
(Millions)	2015	2014	2014	2015	2014	2014
Discontinued operations, net of tax	$—	$(0.8)	(100.0)%	$(0.8)	$12.1	N/A

Second Quarter 2015 Compared with Second Quarter 2014

The loss from discontinued operations, net of tax, decreased $0.8 million in the second quarter of 2015. This decrease was driven by the sale of IES's retail energy business in November 2014. During the second quarter of 2014, we recognized after-tax losses from discontinued operations of $0.7 million related to the operations of IES's retail energy business. See Note 3, Dispositions, for more information.

Six Months 2015 Compared with Six Months 2014

Earnings from discontinued operations, net of tax, decreased $12.9 million in 2015. This decrease was driven by the sale of IES's retail energy business in November 2014. During the first six months of 2014, we recognized after-tax earnings from discontinued operations of $12.3 million related to the operations of IES's retail energy business. The loss from discontinued operations during 2015 was primarily the result of a working capital adjustment related to the sale. See Note 3, Dispositions, for more information.

LIQUIDITY AND CAPITAL RESOURCES

We believe we have adequate resources to fund ongoing operations and future capital expenditures. These resources include cash balances, liquid assets, operating cash flows, access to debt capital markets, available borrowing capacity under existing credit facilities, and equity contributions from our parent company. Our borrowing costs can be impacted by short-term and long-term debt ratings assigned by independent credit rating agencies, as well as the market rates for interest. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside of our control.

Operating Cash Flows

During the six months ended June 30, 2015, net cash provided by operating activities was $673.6 million, compared with $591.1 million during the same period in 2014. The $82.5 million increase in net cash provided by operating activities was driven by:

- A $138.7 million increase in cash related to decreased operating and maintenance costs in 2015. The decrease in operating and maintenance costs was partially driven by the sales of the IES retail energy business in November 2014 and UPPCO in August 2014. See Note 3, Dispositions, for more information. In addition, the utilities had lower electric maintenance costs, lower natural gas distribution costs, and lower bad debt expense in 2015.

- A $63.3 million decrease in contributions to pension and other postretirement benefit plans in 2015.

- A $34.5 million increase in cash from customer prepayments and credit balances. In 2015, customer prepayments grew during the warmer winter.

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These increases in cash were partially offset by:

- A $131.6 million net decrease in cash related to lower collections from customers, partially offset by an increase in cash resulting from lower payments for natural gas, fuel, and purchased power in 2015. This net decrease was mainly due to the sales of the IES retail energy business in November 2014 and UPPCO in August 2014. See Note 3, Dispositions, for more information. Lower commodity prices and warmer weather in 2015 also contributed to the decrease.

- A $13.8 million decrease in cash received from income taxes, primarily driven by a lower federal income tax refund received in 2015, partially offset by state income tax refunds received in 2015.

- A $6.1 million decrease in cash due to higher environmental remediation activities in 2015.

- A $5.9 million decrease in cash driven by higher collateral requirements in 2015. Additional collateral was required by MISO as a result of the increased credit exposure of the combined companies that resulted from the WEC Merger.

Investing Cash Flows

During the six months ended June 30, 2015, net cash used for investing activities was $395.7 million, compared with $429.8 million during the same period in 2014. The $34.1 million decrease in net cash used for investing activities was driven by:

- A $50.7 million increase in cash due to lower funding of the rabbi trust in 2015. See Note 13, Employee Benefit Plans, for more information.

- Cash proceeds of $47.6 million received from the sale of certain PDL solar powered generation plants in 2015.

- A $14.1 million increase in cash due to the withdrawal of restricted cash from the rabbi trust to make qualified payments in 2015.

- A $9.7 million increase in cash due to lower purchases of renewable energy certificates in 2015, driven by the sale of the IES retail energy business in November 2014. See Note 3, Dispositions, for more information.

- A $6.8 million increase in cash due to lower contributions to our transmission affiliate in 2015.

These decreases in cash used were partially offset by:

- An $86.6 million increase in cash used for capital expenditures (discussed below) in 2015.

- A cash payment of $11.0 million to purchase a natural gas distribution business in Minnesota in 2015.

Capital Expenditures

Capital expenditures by business segment for the six months ended June 30 were as follows:

Reportable Segment (millions)	2015	2014	Change in 2015 Over 2014
Wisconsin	$167.4	$124.0	$43.4
Illinois	169.9	120.2	49.7

Other states	18.1	21.1	(3.0)
Corporate and other	69.1	72.6	(3.5)
Integrys Holding consolidated	$424.5	$337.9	$86.6

The increase in capital expenditures in the Wisconsin segment in 2015 was primarily due to the ReACT™ project at Weston 3 and the System Modernization and Reliability Project, partially offset by lower period-over-period capital expenditures related to environmental compliance projects at the Columbia plant.

The increase in capital expenditures at the Illinois segment was primarily due to increased work on the AMRP at PGL in 2015.

Financing Cash Flows

During the six months ended June 30, 2015, net cash used for financing activities was $139.6 million, compared with $138.6 million during the same period in 2014. The $1.0 million increase in net cash used for financing activities was driven by:

- A $97.9 million decrease in cash due to changes in net commercial paper activity.

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- A $7.8 million decrease in cash received from stock option exercises in 2015.

These decreases in cash were partially offset by:

- A $100.0 million increase in cash due to lower repayments of long-term debt in 2015.

- A $5.4 million decrease in cash used to purchase shares of our common stock to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans in 2015.

Significant Financing Activities

For information on short-term debt, see Note 8, Short-Term Debt and Lines of Credit.

For information on long-term debt, see Note 9, Long-Term Debt.

Credit Ratings

Access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

Our current credit ratings and the credit ratings for WPS, PGL, and NSG are listed in the table below:

Credit Ratings	Standard & Poor's	Moody's
Integrys Holding		
Issuer credit rating	A-	A3
Senior unsecured debt	BBB+	A3
Commercial paper	A-2	P-2
Junior subordinated notes	BBB	Baa1
WPS		
Issuer credit rating	A-	A1
First mortgage bonds	N/A	Aa2
Senior secured debt	A	Aa2
Preferred stock	BBB	A3
Commercial paper	A-2	P-1
PGL		
Issuer credit rating	A-	A2
Senior secured debt	N/A	Aa3
Commercial paper	A-2	P-1
NSG		
Issuer credit rating	A-	A2

Credit ratings are not recommendations to buy or sell securities. They are subject to change, and each rating should be evaluated independently of any other rating.

On July 1, 2015, Moody's affirmed our credit ratings, assigned an A3 issuer credit rating for the first time, and affirmed our rating outlook is stable. The issuer rating reflects the stability of our underlying operating cash flows generated from our five regulated utility subsidiaries, a diverse multistate service territory that provides generally sound regulatory support.

Future Capital Requirements and Resources

Contractual Obligations

Our total contractual obligations and other commercial commitments were $10,131.8 million as of June 30, 2015, compared with $10,238.5 million as of December 31, 2014.

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Capital Requirements

In our previously filed Quarterly Report on Form 10-Q for the quarter ended March 31, 2015, we disclosed projected capital expenditures of $2.9 billion for 2015 through 2017 (including amounts already expended in 2015). This projection included approximately $320.0 million of capital expenditures associated with the potential addition of an electric generator at the Fox Energy Center site, which are currently under review as a result of the order from the PSCW approving the WEC Merger. See Management's Discussion and Analysis of Financial Condition and Results of Operations – Other Future Considerations for more information. In addition, all of our projected capital expenditures are being reviewed in connection with the WEC Merger.

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management strategies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage our liquidity and capital resource needs. We plan to meet our capital requirements for the period 2015 through 2017 primarily through internally generated funds (net of forecasted dividend payments), dividends from our subsidiaries, and equity infusions from WEC. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

WPS currently has a shelf registration statement under which it may issue up to $500.0 million of additional senior debt securities and/or first mortgage bonds. Amounts, prices, and terms will be determined at the time of future offerings.

At June 30, 2015, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 8, Short-Term Debt and Lines of Credit, for more information on credit facilities and other short-term credit agreements.

Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our 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. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends to our parent, WEC, or other future funding obligations. See Note 15, Common Equity, for more information on dividend restrictions.

Other Future Considerations

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. The allegations mainly focus on the management of the AMRP. The initiating order stated that the investigation would also include any further allegations of a similar nature as they pertain to AMRP. The Illinois Attorney General’s office is also conducting an investigation into the same matters. The investigations are ongoing. We plan to engage a nationally recognized firm to help conduct an independent, bottom up review of the cost, scope, and schedule for the program.

Potential Addition of an Electric Generator at the Fox Energy Center Site

In 2013, WPS announced a need for an additional 400 to 500 megawatts of electric generating capacity by 2019 to meet the energy needs of its customers. After evaluating various options, WPS proposed building a new 400 megawatt natural gas-fired, combined-cycle generating unit for approximately $517.0 million to be located at its Fox Energy Center site. In January 2015, WPS filed an application with the PSCW for a Certificate of Public Convenience and Necessity. In June 2015, WPS withdrew its application for a Certificate of Public Convenience and Necessity in compliance with a May 2015 order from the PSCW approving the WEC Merger. WPS and Wisconsin Electric Power Company (Wisconsin Electric Power) expect to submit to the PSCW a joint integrated resource plan for their combined loads during the third quarter of 2015 in order for the PSCW to further evaluate the need for the potential new unit.

Presque Isle System Support Resource (SSR) Costs

In August 2013, Wisconsin Electric Power notified MISO of its intention to suspend the operation of Units 5 through 9 of its Presque Isle generating facility for 16 months, starting February 1, 2014. MISO notified Wisconsin Electric Power in October 2013 that the Presque Isle facilities are required for reliability and would be SSR-designated. Under the terms of the SSR Tariff, in exchange for keeping the units in service, MISO will compensate Wisconsin Electric Power by allocating the SSR costs associated with the operation of the Presque Isle units to regulated and nonregulated load-serving entities, including WPS, based on load ratio share within the ATC footprint. In May 2015, MISO made a compliance filing regarding the allocation of Presque Isle SSR costs, and did not allocate any of these SSR costs to WPS. This and several other FERC dockets and rehearing requests regarding the amount and allocation of Presque Isle SSR costs are still pending.

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Wisconsin Electric Power notified MISO of its intent to rescind its decision to retire the Presque Isle Facility and requested termination of the SSR agreement, effective February 1, 2015. This intent to rescind was driven by a settlement agreement related to the WEC Merger. In April 2015, the FERC approved the termination of the SSR agreement effective February 1, 2015.

Based on the currently approved allocation method, no SSR costs would be required for WPS for the SSR-designated period, which ended February 1, 2015. A potential reallocation of the Presque Isle SSR costs based on the pending FERC dockets and rehearing requests may result in a change. If any SSR costs are allocated to WPS, costs related to retail customers will be deferred based on an order from the PSCW. The appropriate ratemaking treatment will be determined by the PSCW after December 31, 2015. Costs for Michigan customers would be recovered through the Power Supply Cost Recovery mechanism, and costs for wholesale customers would be recovered through formula rates.

MISO Transmission Owner Return on Equity Complaint

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting, among other things, to reduce the base return on equity (ROE) used by MISO transmission owners, including ATC, to 9.15%. ATC's current authorized ROE is 12.2%. In October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 12, 2013. However, the FERC denied all other aspects of the complaint, including that the use of capital structures that include more than 50% common equity is unjust and unreasonable. The FERC ordered preliminary hearings to begin and expects to issue an initial decision by November 30, 2015.

In October 2014, the FERC issued an order, in regard to a similar complaint, to reduce the base ROE for New England transmission owners from their existing rate of 11.14% to 10.57%. The FERC used a revised method for determining the appropriate ROE for FERC-jurisdictional electric utilities, which incorporates both short-term and long-term measures of growth in dividends.

In January 2015, in response to a filing made by MISO transmission owners, the FERC approved a 50-basis point adder to the authorized ROE based on the transmission owners' participation as members in a regional transmission organization. The FERC ordered an effective date of January 6, 2015, subject to refund, and subject to the outcome of the November 2013 complaint proceeding discussed above. Collection of the ROE adder was also deferred pending the outcome of the November 2013 complaint proceeding.

In February 2015, a second complaint was filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners, including ATC, to 8.67%, with a refund effective date retroactive to the filing date of the complaint.

The FERC has stated that it expects future decisions on pending complaints related to similar ROE issues will be guided by the New England transmission decision. Any change to ATC's ROE could result in lower equity earnings and dividends from ATC in the future. Although we are currently unable to determine how the FERC may rule in this complaint, we believe it is probable that a refund will be required upon resolution of this issue.

Climate Change

On August 3, 2015, the EPA issued final guidelines relating to greenhouse gas (GHG) emissions from existing generating units, and published final performance standards for modified and reconstructed generating units and new fossil fueled power plants. The final guidelines for existing fossil generating units seek to attain state-specific GHG rate limits by 2030, and require states to submit plans as early as September 2016. States requesting an extension would be required to submit final plans by September 2018, either alone or in cooperation 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 aggressive GHG reductions in Wisconsin and Michigan. The proposed program consists of building blocks that include a combination of power plant efficiency improvements, increased reliance on combined cycle gas units, and adding new renewable energy resources.

We are in the process of reviewing the final guidelines for existing generating units to determine the potential impacts to our operations, but these guidelines could result in significant additional compliance costs, including capital expenditures, impact how we operate our existing fossil fueled power plants, and could have a material adverse impact on our operating costs. In addition, several states have indicated that they intend to challenge these new rules, and any state compliance plans that are developed could be subject to change based upon the outcome of this litigation.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies and considered whether any new critical accounting estimates or other significant changes to our accounting policies require any additional disclosures. We have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2014, are still current and that there have been no significant changes, except as follows:

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Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2015. No impairments were recorded as a result of these tests. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. The fair value was calculated using an equal weighting of the income approach and the market approach.

For the income approach, we used internal forecasts to project cash flows. Any forecast contains a degree of uncertainty, and changes in these cash flows could significantly increase or decrease the fair value of a reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease.

Key assumptions used in the income approach included return on equity (ROE) for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is determined based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is based on its current allowed ROE adjusted for forecasted disallowed costs and expectations regarding the direction and magnitude of movements in interest rates. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

We used the guideline company method for the market approach. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company. We applied multiples derived from these guideline companies to the appropriate operating metric for the utility reporting units to determine indications of fair value.

The underlying assumptions and estimates used in the impairment test are made as of a point in time. Subsequent changes in these assumptions and estimates could change the results of the test.

The fair values of the WPS natural gas utility and NSG reporting units exceeded the carrying values by a substantial amount. Based on these results, these reporting units are not at risk of failing step one of the goodwill impairment test.

The fair values calculated in the first step of the test for ITF, MERC, MGU, and PGL exceeded the carrying values by approximately 3% to 23%. Due to the subjectivity of the assumptions and estimates underlying the impairment analyses, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, which would result in a fair value at carrying value, causing the applicable reporting unit to fail step one of the test. Failing step one would result in a goodwill impairment that could be material, as the carrying value of the identifiable assets and liabilities is considered fair value for regulated companies. This is because a regulator would typically not allow the assets and liabilities of a regulated company to be increased or decreased, allowing for a change in recovery from ratepayers, as a result of an acquisition or other change in ownership. If the carrying value exceeds the calculated fair value of the reporting unit, the excess would be recorded as a goodwill impairment.

Change in Key Inputs (in basis points)	ITF	MERC	MGU	PGL
Discount rate	20	150	200	200
Terminal year return on equity	N/A	(365)	(460)	(560)
Terminal year growth rate	(25)	(150)	N/A *	N/A *

* Even with a terminal year growth rate of 0%, assuming all other inputs remained constant, MGU and PGL would still have passed the first step of the goodwill impairment test.

Our reporting units had the following goodwill balances at April 1, 2015:

(Millions, except percentages)	Goodwill	Percentage of Total Goodwill	
PGL	$401.2	61.2	%
MERC	127.6	19.5	%
WPS's natural gas utility	36.4	5.5	%
NSG	36.1	5.5	%
MGU	34.5	5.3	%
ITF	19.6	3.0	%
Total goodwill	$655.4	100.0	%

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Our market risks have not changed materially from the market risks reported in our 2014 Annual Report on Form 10-K.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended June 30, 2015, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

On June 29, 2015, the WEC Merger was completed. WEC is currently in the process of integrating our operations, processes, and internal controls. See Note 2, WEC Merger, for more information.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Since the announcement of the WEC Merger, we and our board of directors, along with Wisconsin Energy, have been named as defendants in ten separate purported class action lawsuits filed in Brown County, Wisconsin (three of the cases - Rubin v. Integrys Energy Group, Inc., et al.; Blachor v. Integrys Energy Group, Inc., et al.; and Albera v. Integrys Energy Group, Inc., et al.), Milwaukee County, Wisconsin (two of the cases - Amo v. Integrys Energy Group, Inc., et al. and Inman v. Integrys Energy Group, Inc., et al.), Cook County, Illinois (two of the cases - Taxman v. Integrys Energy Group, Inc., et al., and Curley v. Integrys Energy Group, Inc., et al.), and the federal court for the Northern District of Illinois (three of the cases - Steiner v. Integrys Energy Group, Inc., et al., Tri-State Joint Fund v. Integrys Energy Group, Inc., et al., and Collison v. Integrys Energy Group, Inc., et al.). In the Tri-State Joint Fund case, Wisconsin Energy's Chief Executive Officer was also named as a defendant. The cases were brought on behalf of proposed classes consisting of shareholders of Integrys Energy Group. The complaints allege, among other things, that our board members breached their fiduciary duties by failing to maximize the value to be received by our shareholders, that Wisconsin Energy aided and abetted the breaches of fiduciary duty, and that the joint proxy statement/prospectus contains material misstatements and omissions. The Brown County and Cook County cases have been dismissed in favor of the Milwaukee County actions. On November 12, 2014, the parties entered into a Memorandum of Understanding, which provides the basis for a complete settlement of these actions. A Stipulation of Settlement was presented to the Court in late July 2015. The Court has scheduled a hearing for September 8, 2015, for preliminary approval of the settlement.

See Note 11, Commitments and Contingencies, for information on other material legal proceedings and matters.

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Item 1A. Risk Factors

Other than the inapplicability of the "Risks Related to the Proposed Merger with Wisconsin Energy Corporation (Wisconsin Energy)," which have been replaced with the risks set forth below, there were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2014 Annual Report on Form 10-K, which was filed with the SEC on March 2, 2015.

Risks Related to the WEC Merger

The WEC Merger may not achieve its anticipated results, and we may be unable to integrate our operations as expected.

We entered into the WEC Merger Agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of the two companies can be integrated in an efficient, effective, and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees; the disruption of each company's ongoing businesses, processes, and systems; or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect our ability to achieve the anticipated benefits of the transaction as and when expected. We may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results and prospects.

The acquisition may adversely affect our ability to attract and retain key employees.

Current and prospective employees may experience uncertainty about their future roles at the company as a result of the merger. In addition, current and prospective employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect our ability to attract and retain key management and other personnel.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Dividend Restrictions

On June 29, 2015, all of our outstanding common shares were acquired by WEC. Our ability to pay dividends or return capital to WEC is largely dependent upon the availability of funds from our subsidiaries. See Note 15, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends.

Item 6. Exhibits

The documents listed in the Exhibit Index are attached as exhibits or incorporated by reference herein.

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SIGNATURE

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

INTEGRYS HOLDING, INC.
(Registrant)

Date: August 5, 2015

/s/ Stephen P. Dickson
Stephen P. Dickson
Vice President and Controller

(Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS HOLDING
EXHIBIT INDEX TO FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2015

Exhibit No.	Description
3.1	Articles of Incorporation of Integrys Holding, Inc. (Incorporated by reference to Exhibit 3.1 to Integrys Holding, Inc.'s June 29, 2015 Form 8-K.)
3.2	By-Laws of Integrys Holding, Inc. (Incorporated by reference to Exhibit 3.2 to Integrys Holding Inc.'s June 29, 2015 Form 8-K.)
4.1	Sixth Supplemental Indenture, effective June 29, 2015, between Integrys Holding, Inc. and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.1 to Integrys Holding Inc.'s June 29, 2015 Form 8-K.)
4.2	Third Supplemental Indenture, effective June 29, 2015, between Integrys Holding, Inc. and U.S. Bank National Association, as trustee. (Incorporated by reference to Exhibit 4.2 to Integrys Holding Inc.’s June 29, 2015 Form 8-K.)
10.1	Assumption Agreement, effective June 29, 2015, executed by Integrys Holding, Inc., related to the Five-Year Credit Agreement dated as of June 13, 2012 among Integrys Energy Group, Inc., U.S. Bank National Association, as administrative agent, and various other financial institutions. (Incorporated by reference to Exhibit 10.1 to Integrys Holding Inc.'s June 29, 2015 Form 8-K.)
10.2	Assumption Agreement, effective June 29, 2015, executed by Integrys Holding, Inc., related to the Five-Year Credit Agreement dated as of May 8, 2014 among Integrys Energy Group, Inc., JPMorgan Chase Bank N.A., as administrative agent, and various other financial institutions. (Incorporated by reference to Exhibit 10.2 to Integrys Holding Inc.'s June 29, 2015 Form 8-K.)
10.3	Letter Agreement by and between WEC Energy Group, Inc. and Charles R. Matthews, dated as of July 13, 2015. (Exhibit 10.2 to WEC Energy Group Inc.'s June 30, 2015 Form 10-Q.)
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Holding, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Holding, Inc.
32.1	Written Statement of the Chief Executive Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Holding, Inc.
32.2	Written Statement of the Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Holding, Inc.
101	Financial statements from the Quarterly Report on Form 10-Q of Integrys Holding, Inc. for the quarter ended June 30, 2015, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Statements of Comprehensive Income, (iii) the Condensed Consolidated Balance Sheets, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity

information.