INTEGRYS ENERGY GROUP, INC.
Form 10-Q
May 05, 2015

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 March 31, 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 ENERGY GROUP, INC. (A Wisconsin Corporation) 200 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

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, $1 par value,
79,963,091 shares outstanding at
May 4, 2015

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For the Quarter Ended March 31, 2015
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Acronyms Used in this Quarterly Report on Form 10-Q

AFUDC	Allowance for Funds Used During Construction
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
IBS	Integrys Business Support, LLC
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
PDI	WPS Power Development LLC
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
WDNR	Wisconsin Department of Natural Resources
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 possibility that the proposed merger with Wisconsin Energy Corporation does not close (including, but not limited to, due to the failure to satisfy the closing conditions), disruption from the proposed merger making it more difficult to maintain our business and operational relationships, and the risk that unexpected costs will be incurred during this process;
- 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 ability to retain market-based rate authority;
- 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 ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)	Three Months Ended March 31	
(Millions, except per share data)	2015	2014
Operating revenues	$1,163.2	$1,638.0
Cost of sales	577.7	975.6
Operating and maintenance expense	261.0	332.6
Depreciation and amortization expense	74.7	70.6
Taxes other than income taxes	25.6	26.9
Operating income	224.2	232.3
Earnings from equity method investments	17.5	22.9
Miscellaneous income	6.6	5.8
Interest expense	38.2	38.9
Other expense	(14.1)	(10.2)
Income before taxes	210.1	222.1
Provision for income taxes	78.9	81.9
Net income from continuing operations	131.2	140.2
Discontinued operations, net of tax	(0.9)	12.9
Net income	130.3	153.1
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	—	0.1
Net income attributed to common shareholders	$129.5	$152.4
Average shares of common stock		
Basic	80.2	80.2
Diluted	80.8	80.5
Earnings per common share (basic)		
Net income from continuing operations	$1.62	$1.74
Discontinued operations, net of tax	(0.01)	0.16
Earnings per common share (basic)	$1.61	$1.90
Earnings per common share (diluted)		
Net income from continuing operations	$1.61	$1.73
Discontinued operations, net of tax	(0.01)	0.16
Earnings per common share (diluted)	$1.60	$1.89
Dividends per common share declared	$0.68	$0.68

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)

(Millions)	Three Months Ended March 31 2015	2014
Net income	$130.3	$153.1
Other comprehensive income (loss), net of tax:		
Cash flow hedges		
Reclassification of net losses (gains) to net income, net of tax of $0.1 million and $0.9 million, respectively	0.1	(0.6)
Defined benefit plans		
Pension and other postretirement benefit costs arising during period, net of tax of an insignificant amount for all periods presented	—	(0.1)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.5 million and $0.3 million, respectively	0.7	0.3
Defined benefit plans, net	0.7	0.2
Other comprehensive income (loss), net of tax	0.8	(0.4)
Comprehensive income	131.1	152.7
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	—	0.1
Comprehensive income attributed to common shareholders	$130.3	$152.0

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)	March 31	December 31
(Millions, except share and per share data)	2015	2014
Assets		
Cash and cash equivalents	$86.4	$ 18.0
Accounts receivable and accrued unbilled revenues, net of reserves of $58.3 and $63.3, respectively	720.8	699.8
Inventories	179.9	327.2
Regulatory assets	86.2	118.9
Assets held for sale	51.5	52.2
Deferred income taxes	39.8	52.4
Prepaid taxes	51.7	136.2
Other current assets	43.0	57.4
Current assets	1,259.3	1,462.1
Property, plant, and equipment, net of accumulated depreciation of $3,330.2 and $3,322.0, respectively	6,928.8	6,827.7
Regulatory assets	1,507.3	1,513.6
Equity method investments	556.0	550.6
Goodwill	655.4	655.4
Other long-term assets	262.2	272.6
Total assets	$11,169.0	$ 11,282.0
Liabilities and Equity		
Short-term debt	$133.3	$ 317.6
Current portion of long-term debt	125.0	125.0
Accounts payable	414.6	490.7
Accrued taxes	108.6	87.7
Regulatory liabilities	171.6	153.7
Liabilities held for sale	13.6	13.8
Other current liabilities	282.1	261.0
Current liabilities	1,248.8	1,449.5
Long-term debt	2,956.3	2,956.3
Deferred income taxes	1,599.5	1,570.0
Deferred investment tax credits	63.6	60.6
Regulatory liabilities	402.4	399.9
Environmental remediation liabilities	573.2	579.9
Pension and other postretirement benefit obligations	271.2	274.6
Asset retirement obligations	485.0	479.1
Other long-term liabilities	155.3	161.3
Long-term liabilities	6,506.5	6,481.7
Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,534,171 shares outstanding	80.0	80.0
Additional paid-in capital	2,629.2	2,642.2

Retained earnings	701.1	626.0
Accumulated other comprehensive loss	(26.8)	(27.6)
Shares in deferred compensation trust	(20.9)	(20.9)
Total common shareholders’ equity	3,362.6	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	$11,169.0	$ 11,282.0

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)	Three Months Ended March 31	
(Millions)	2015	2014
Operating Activities		
Net income	$130.3	$153.1
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization expense	74.7	71.3
Recoveries and refunds of regulatory assets and liabilities	18.1	54.1
Net unrealized gains on energy contracts	(0.5)	(19.7)
Bad debt expense	9.2	19.3
Pension and other postretirement expense	7.7	7.2
Pension and other postretirement contributions	(2.9)	(68.6)
Deferred income taxes and investment tax credits	45.2	90.3
Equity income, net of dividends	(4.0)	(3.9)
Other	(10.9)	1.1
Changes in working capital		
Collateral on deposit	0.6	(37.0)
Accounts receivable and accrued unbilled revenues	(38.9)	(531.5)
Inventories	146.9	121.6
Other current assets	104.9	(65.3)
Accounts payable	(40.8)	272.1
Temporary LIFO liquidation credit	33.5	150.9
Other current liabilities	51.1	54.7
Net cash provided by operating activities	524.2	269.7
Investing Activities		
Capital expenditures	(208.8)	(159.6)
Capital contributions to equity method investments	(1.7)	(5.1)
Withdrawal of restricted cash from Rabbi trust for qualifying payments	10.9	—
Other	2.1	1.4
Net cash used for investing activities	(197.5)	(163.3)
Financing Activities		
Short-term debt, net	(184.3)	(4.1)
Shares purchased for stock-based compensation	(17.5)	(9.8)
Payment of dividends		
Preferred stock of subsidiary	(0.8)	(0.8)
Common stock	(54.1)	(54.1)
Other	(1.6)	(3.3)
Net cash used for financing activities	(258.3)	(72.1)
Net change in cash and cash equivalents	68.4	34.3
Cash and cash equivalents at beginning of period	18.0	22.3
Cash and cash equivalents at end of period	$86.4	$56.6
Cash paid for interest	$13.9	$13.4
Cash received for income taxes	$(51.1)	$(62.7)

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

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INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
March 31, 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 Energy Group, Inc.

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.

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

The assets and liabilities associated with the potential sale of certain PDI solar assets were reclassified as held for sale on our December 31, 2014 balance sheet to be consistent with the current period presentation. In addition, the operations of IES's retail energy business were reclassified as discontinued operations on our income statement for the three months ended March 31, 2014. See Note 4, Dispositions, for more information on these sales.

Note 2—Proposed Merger with Wisconsin Energy Corporation

In June 2014, we entered into an Agreement and Plan of Merger (Agreement) with Wisconsin Energy Corporation (Wisconsin Energy). Under this Agreement, upon the close of the transaction our shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash for each share of our common stock then owned. In addition, under the Agreement all of our unvested stock-based compensation awards will fully vest upon the close of the transaction and will be paid out in cash to award recipients. Upon closing of the transaction, our shareholders will own approximately 28% of the combined company, and Wisconsin Energy shareholders will own approximately 72%.

The combined entity will be named WEC Energy Group, Inc. and will serve natural gas and electric customers across Wisconsin, Illinois, Michigan, and Minnesota.

This transaction was approved unanimously by the Boards of Directors of both companies. It was also approved by the shareholders of both companies. In October 2014, the Department of Justice closed its review of the transaction and the Federal Trade Commission granted early termination of the waiting period under the Hart-Scott-Rodino Act. In April 2015, the transaction was approved by the Federal Communications Commission, the FERC, and the MPSC. On April 30, 2015, the transaction was verbally approved by the PSCW subject to certain conditions. A final written order is expected from the PSCW in May 2015. The transaction is still subject to approvals from the ICC and the MPUC, as well as other customary closing conditions. We expect the merger transaction to close by the end of this summer.

Note 3—Acquisitions

Purchase of Alliant Energy Corporation's Natural Gas Distribution Business in Southeast Minnesota

On April 30, 2015, MERC acquired Alliant Energy Corporation's natural gas distribution business in southeast Minnesota for $13.6 million. The purchase price included a cash payment of $11.0 million and the issuance of a promissory note to Alliant Energy Corporation for $2.6 million. The purchase price was based on the estimated book value as of the closing date and is subject to post-closing adjustments. This transaction was not material to us.

Note 4—Dispositions

Discontinued Operations

See Note 5, Cash and Cash Equivalents, for cash flow information related to discontinued operations.

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Holding Company and Other Segment – Potential Sale of Combined Locks Energy Center (Combined Locks)

We are currently pursuing the sale of Combined Locks, a natural gas-fired co-generation facility located in Wisconsin. Combined Locks had $0.7 million of assets that were classified as held for sale on the balance sheets at March 31, 2015, and December 31, 2014, which included inventories and property, plant, and equipment. During each of the three months ended March 31, 2015, and 2014, we recorded after-tax losses of $0.1 million in discontinued operations related to Combined Locks.

IES 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 has been updated for a working capital adjustment made in the first quarter of 2015 and reflected in the tables below. As part of the stock purchase agreement, we provided guarantees expiring during the second quarter of 2015, which supported the IES retail energy business. 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.

The sale of the retail energy business was the result of a previously announced shift in our strategy to focus on our regulated businesses. Therefore, its results of operations were classified as discontinued operations beginning in the fourth quarter of 2014.

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

(Millions)	As of the Closing Date in November 2014
Cash and cash equivalents	$7.6
Accounts receivable and accrued unbilled revenues, net of reserves of $1.8	293.4
Inventories	52.2
Current assets from risk management activities	234.8
Other current assets	75.1
Property, plant, and equipment, net of accumulated depreciation of $16.6	4.5
Long-term assets from risk management activities	106.9
Other long-term assets	25.5
Total assets	$800.0
Accounts payable	$186.9
Current liabilities from risk management activities	169.7
Accrued taxes	0.8
Other current liabilities	6.7
Long-term liabilities from risk management activities	79.5
Other long-term liabilities	0.3
Total liabilities	$443.9

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

The following table shows the components of discontinued operations related to the sale of the IES retail energy business recorded on the income statements for the three months ended March 31:

(Millions)	2015	2014
Revenues	$—	$1,289.6
Cost of sales	—	(1,234.8)
Operating and maintenance expense	(1.2)	(32.0)
Depreciation and amortization expense	—	(0.7)
Taxes other than income taxes	(0.2)	(1.2)
Miscellaneous income	0.1	0.2
Interest expense	—	(0.2)
(Loss) income before taxes	(1.3)	20.9
Benefit (provision) for income taxes	0.5	(7.9)
Discontinued operations, net of tax	$(0.8)	$13.0

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Dispositions

Holding Company and Other Segment – Potential Sale of Certain PDI Solar Assets

In the first quarter of 2015, management began implementing a plan to sell certain solar assets owned by PDI. The potential sale of these assets meets the criteria in the accounting guidance to qualify as held for sale but does not meet the requirements to qualify as discontinued operations. The potential sale of these assets does not represent a shift in our corporate strategy and will not have a major effect on our operations and financial results. Therefore, the results of operations of the PDI solar assets will remain in continuing operations.

The following table shows the carrying values of the major classes of assets and liabilities included as held for sale on the balance sheets:

(Millions)	March 31, 2015	December 31, 2014
Property, plant, and equipment, net of accumulated depreciation of $22.1 and $21.1, respectively	$31.1	$32.1
Equity method investments	18.5	18.2
Other long-term assets	1.2	1.2
Total assets	$50.8	$51.5
Current liabilities	$0.3	$0.3
Deferred investment tax credits	4.7	5.0
Asset retirement obligations	1.1	1.1
Other long-term liabilities	7.5	7.4
Total liabilities	$13.6	$13.8

Electric Utility Segment – Sale of UPPCO

In August 2014, we sold all of the 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. The sale of UPPCO was evaluated for accounting purposes prior to our early adoption of ASU 2014-08. UPPCO met the criteria in the accounting guidance to qualify as held for sale but did not meet the requirements to qualify as discontinued operations as WPS has significant continuing cash flows related to certain power purchase transactions with UPPCO that continued after the sale. Therefore, UPPCO's results of operations through the sale date remain in continuing operations.

Note 5—Cash and Cash Equivalents

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

Continuing Operations

Significant noncash transactions related to continuing operations were:

	Three Months Ended March 31	
(Millions)	2015	2014
Construction costs funded through accounts payable	$134.0	$92.3
ITF fueling station sale financed with note receivable	2.8	—
Equity issued for employee stock ownership plan	—	1.7

At March 31, 2015, restricted cash of $12.5 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 proposed merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information about the proposed merger. See Note 13, Employee Benefit Plans, for more information on the rabbi trust funding requirements.

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Discontinued Operations

Significant noncash transactions and other information related to discontinued operations are disclosed below. There were no significant investing activities for the periods presented.

	Three Months Ended March 31	
(Millions)	2015	2014
Operating Activities		
Net unrealized gains on energy contracts	$—	$(19.6)
Deferred income taxes and investment tax credits	—	11.5
Other	1.3	6.7

Note 6—Investment in ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at March 31, 2015. ATC is a for-profit, transmission-only company regulated by FERC.

The following table shows changes to our investment in ATC:

	Three Months Ended March 31	
(Millions)	2015	2014
Balance at the beginning of period	$536.7	$508.4
Add: Earnings from equity method investment	17.0	22.5
Add: Capital contributions	1.7	5.1
Less: Dividends received	13.6	18.4
Balance at the end of period	$541.8	$517.6

ATC is currently named in a complaint filed with the FERC requesting a reduction in the base return on equity (ROE) used by MISO transmission owners to 9.15%. ATC's current authorized ROE is 12.2%. 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, based on rulings in a similar complaint. As a result, our equity earnings and corresponding equity method investment in ATC reflect the impact of a reduction to earnings based on this issue. Our equity earnings for the first quarter of 2015 also included a reduction of $4.8 million related to prior years due to a revision to the estimated refund.

Financial data for all of ATC is included in the following tables:

	Three Months Ended March 31	
(Millions)	2015	2014
Income statement data		
Revenues	$152.4	$163.3
Operating expenses	80.0	78.6
Other expense	24.4	21.6
Net income	$48.0	$63.1

(Millions)	March 31, 2015	December 31, 2014
Balance sheet data		
Current assets	$69.4	$66.4
Noncurrent assets	3,779.3	3,728.7
Total assets	$3,848.7	$3,795.1

Current liabilities	$325.7	$313.1
Long-term debt	1,701.0	1,701.0
Other noncurrent liabilities	188.9	163.8
Shareholders’ equity	1,633.1	1,617.2
Total liabilities and shareholders’ equity	$3,848.7	$3,795.1

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Note 7—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. At March 31, 2015, we had a temporary LIFO liquidation credit of $33.5 million recorded within other current liabilities on our balance sheet. Due to seasonality requirements, PGL and NSG expect interim reductions in LIFO layers to be replenished by year end.

Note 8—Goodwill and Other Intangible Assets

We had no changes to the carrying amount of goodwill during the three months ended March 31, 2015, and 2014.

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

	March 31, 2015			December 31, 2014		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Contractual service agreements [1]	$15.6	$ (5.1)	$10.5	$15.6	$ (4.3)	$11.3
Customer-owned equipment modifications [2]	4.0	(1.2)	2.8	4.0	(1.2)	2.8
Intellectual property [3]	3.4	(0.9)	2.5	3.4	(0.8)	2.6
Nonregulated easements [4]	3.9	(1.5)	2.4	3.9	(1.4)	2.5
Compressed natural gas fueling contract assets [5]	5.6	(3.8)	1.8	5.6	(3.6)	2.0
Customer-related [6]	1.9	(0.4)	1.5	1.9	(0.3)	1.6
Other	0.5	(0.3)	0.2	0.5	(0.3)	0.2
Total	$34.9	$ (13.2)	$21.7	$34.9	$ (11.9)	$23.0
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name [7]	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name [7]	1.5	—	1.5	1.5	—	1.5
Other	0.4	—	0.4	—	—	—
Total intangible assets	$45.5	$ (13.2)	$32.3	$45.1	$ (11.9)	$33.2

(1) Represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at the Fox Energy Center. The remaining weighted-average amortization period for these intangible assets at March 31, 2015, was approximately four years.

(2) Relates to modifications made by PDI and ITF to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at March 31, 2015, of approximately nine years.

(3) Represents the fair value of intellectual property at ITF related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period for these intangible assets at March 31, 2015, was approximately seven years.

(4) Relates to easements supporting a pipeline at PDI. The easements are amortized on a straight-line basis, with a remaining amortization period at March 31, 2015, of approximately nine years.

(5) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period for these intangible assets at March 31, 2015, was approximately six years.

(6) Represents customer relationship assets associated with ITF's compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at March 31, 2015, was approximately 12 years.

(7) Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) are wholly-owned subsidiaries of ITF.

The table below shows the amortization we recorded:

	Three Months Ended March 31	
(Millions)	2015	2014
Amortization recorded in cost of sales	$0.3	$0.3
Amortization recorded in depreciation and amortization expense	0.7	0.7
Amortization recorded in regulatory assets	0.3	—

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The following table shows our estimated amortization for the next five years, including amounts recorded through March 31, 2015:

	For the Year Ending December 31				
(Millions)	2015	2016	2017	2018	2019
Amortization to be recorded in cost of sales	$1.1	$0.9	$0.9	$0.8	$0.6
Amortization to be recorded in depreciation and amortization expense	3.0	2.9	2.4	1.9	1.9
Amortization to be recorded in regulatory assets	1.0	1.0	0.5	—	—

Note 9—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	March 31, 2015	December 31, 2014
Commercial paper	$133.3 *	$317.6
Average interest rate on commercial paper outstanding	0.37 %	0.36 %

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

Our average amount of commercial paper borrowings based on daily outstanding balances during the three months ended March 31, 2015, and 2014, was $189.5 million and $247.1 million, respectively.

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	March 31, 2015	December 31, 2014
Revolving credit facility (Integrys Energy Group)	06/13/2017	$285.0	$285.0
Revolving credit facility (Integrys Energy Group) *	05/08/2019	465.0	465.0
Revolving credit facility (WPS)	05/08/2019	135.0	135.0
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0
Total short-term credit capacity		$1,250.0	$1,250.0
Less:			
Letters of credit issued inside credit facilities		$0.7	$3.4
Commercial paper outstanding		133.3	317.6
Available capacity under existing agreements		$1,116.0	$929.0

* This credit facility was reduced by $200.0 million in April 2015 due to the transfer of the remaining credit support for IES's retail energy business to Exelon Generation Company, LLC.

Note 10—Income Taxes

We calculate our interim period provision for 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 March 31

	2015	2014
Effective tax rate	37.6 %	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. No other items had a significant impact on our effective tax rates during the three months ended March 31, 2015, and 2014.

During the three months ended March 31, 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 March 31, 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
Natural gas utility supply and transportation	2028	$664.6	$128.8	$171.7	$134.4	$79.6	$52.3	$97.8
Electric utility								
Purchased power	2029	806.1	92.1	42.7	53.3	55.9	57.1	505.0
Coal supply and transportation	2019	155.8	44.3	34.8	33.5	32.1	11.1	—
Total		$1,626.5	$265.2	$249.2	$221.2	$167.6	$120.5	$602.8

(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. WPS announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. 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 Pulliam 5 and 6 and Weston 1 starting with the actual retirement date in 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 March 31, 2015. It is unknown whether the Sierra Club will take further action in the future.

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),

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- 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 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 the Edgewater 4 unit 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) recently 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. The WDNR also issued a Notice of Inquiry (NOI) to WPS alleging that WPS failed to comply with 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 and NOI. 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.

Mercury and Interstate Air Quality Rules

Mercury and Other Hazardous Air Pollutants:
In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which regulates emissions of mercury and other hazardous air pollutants beginning in April 2015. The State of Wisconsin recently revised the compliance dates in the state mercury rule to be consistent with the MATS rule. Projects approved and initiated to address the State of Wisconsin mercury rule are expected to ensure compliance with the mercury limits in the MATS rule. WPS placed in service capital projects for its wholly owned plants in 2015 to achieve the required reductions for MATS compliance in April 2015. These capital costs are expected to be recovered in future rates.

Sulfur Dioxide and Nitrogen Oxide:

In July 2011, the EPA issued a final rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including WPS, challenged in the United States Court of Appeals (Court of Appeals) for the District of Columbia Circuit (D.C. Circuit). The new rule was to become effective in January 2012. However, in December 2011, the CSAPR requirements were stayed by the D.C. Circuit and a previous rule, the Clean Air Interstate Rule (CAIR), was implemented during the stay period. In August 2012, the D.C. Circuit issued their ruling vacating and remanding CSAPR and simultaneously reinstating CAIR pending the issuance of a replacement rule by the EPA. The case was appealed to the United States Supreme Court (Supreme Court), and in April 2014, the Supreme Court upheld the CSAPR rule and remanded the case to the Court of Appeals for the D.C. Circuit. In October 2014, the Court of Appeals granted the EPA's request to lift the stay on CSAPR and changed the compliance deadlines by three years, so that Phase 1 emissions budgets apply in 2015 and 2016, and Phase 2 emissions budgets will apply to 2017 and beyond. We do not expect to incur significant costs to comply with either phase of CSAPR and expect to recover any future compliance costs in future rates.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule were considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they were in compliance with CAIR. This determination was updated when CSAPR was issued (CSAPR satisfied BART). Although particulate emissions also contribute to visibility impairment, the WDNR's modeling for Pulliam Unit 8, the only unit covered by BART, has shown the impairment to be so insignificant that additional capital expenditures or controls may not be warranted.

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Clean Water Act Rule

In August 2014, the EPA issued a final Clean Water Act rule, which established requirements under Section 316(b) to regulate water intake structures at industrial facilities that use large volumes of surface water as cooling water. The new rule became effective in October 2014 and has been challenged by a number of parties. The cases have been consolidated and will be heard in the United States Court of Appeals for the Second Circuit. To the extent that the rule is upheld, WPS will comply with the rule on the timeline required under the regulation. WPS will evaluate the impact of compliance by conducting the studies required by the rule at its facilities. WPS anticipates that the timing for compliance will be incorporated into future wastewater discharge permit renewals. We do not expect to incur significant costs to comply with the Clean Water Act rule at WPS's Weston plant as this plant already has two units equipped with cooling towers that assist with meeting these new requirements. We expect to recover any future compliance costs in future rates.

Manufactured Gas Plant Remediation

Our natural gas utilities, their predecessors, and certain former affiliates operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, our natural gas utilities are required to undertake remedial action with respect to some of these materials. The natural gas utilities are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies.

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA's program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. Our balance sheet includes liabilities of $573.0 million that we have estimated and accrued for as of March 31, 2015, for future undiscounted investigation and cleanup costs for all sites. We may adjust these estimates in the future due to remedial technology, regulatory requirements, remedy determinations, and any claims of natural resource damages. As of March 31, 2015, cash expenditures for environmental remediation not yet recovered in rates were $43.1 million. Our balance sheet also includes a regulatory asset of $616.1 million at March 31, 2015, which is net of insurance recoveries, related to the expected recovery through rates of both cash expenditures and estimated future expenditures.

Management believes that any costs incurred for environmental activities relating to former manufactured gas plant operations that are not recoverable through contributions from other entities or from insurance carriers have been prudently incurred and are, therefore, recoverable through rates for MGU, NSG, PGL, and WPS. Accordingly, we do not expect these costs to have a material impact on our financial statements. However, any changes in the approved rate mechanisms for recovery of these costs, or any adverse conclusions by the various regulatory commissions with respect to the prudence of costs actually incurred, could materially affect recovery of such costs through rates.

Note 12—Guarantees

The following table shows our outstanding guarantees:

	Total Amounts Committed at	Expiration	
(Millions)			1 to 3 Years

	March 31, 2015	Less Than 1 Year		Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$162.5	$91.2	$—	$71.3
Standby letters of credit (2)	1.2	1.1	0.1	—
Surety bonds (3)	25.1	25.1	—	—
Guarantees temporarily retained related to the sale of IES's retail energy business (4)	55.7	38.6	0.8	16.3
Other guarantees (5)	62.4	—	—	62.4
Total guarantees	$306.9	$156.0	$0.9	$150.0

(1) Consists of (a) $5.0 million to support each of the business operations of IBS and PDI and (b) $0.4 million, $108.9 million, and $43.2 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. This amount consists of standby letters of credit issued to support ITF, MERC, MGU, NSG, PDI, PGL, and WPS. This amount is not reflected on our balance sheets.

(3) Primarily for the construction and operation of compressed natural gas fueling stations, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These guarantees 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). During the second quarter of 2015, these guarantees will expire. Exelon was contractually bound to reimburse us for any payments made under the outstanding guarantees. At March 31, 2015, these guarantees consisted of (a) $52.1 million of guarantees supporting commodity transactions; (b) $1.2 million of standby letters of credit; (c) $2.1 million of surety bonds; and (d) $0.3 million related to the sale of WPS Beaver Falls Generation, LLC. The liability related to these guarantees was insignificant. Our exposure under these guarantees related to open transactions at March 31, 2015, was $31.5 million.

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(5) Consists of (a) $34.2 million to support PDI'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. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the law; (c) $11.2 million related to the performance of an operating and maintenance agreement by ITF; and (d) $7.0 million related to other indemnifications primarily for workers compensation coverage. The amounts discussed in items (a), (c), and (d) above are not reflected on our balance sheets.

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 March 31		Three Months Ended March 31	
(Millions)	2015	2014	2015	2014
Service cost	$7.6	$6.6	$5.8	$5.9
Interest cost	17.0	19.7	5.3	7.1
Expected return on plan assets	(26.9)	(28.9)	(7.9)	(8.8)
Loss on plan settlement	0.5	—	—	—
Amortization of prior service cost (credit)	0.1	0.2	(2.6)	(1.3)
Amortization of net actuarial loss	10.5	8.4	1.1	0.7
Net periodic benefit cost	$8.8	$6.0	$1.7	$3.6

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.

Our funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. During the three months ended March 31, 2015, we contributed $2.8 million to our pension plans and $0.1 million to our other postretirement benefit plans. We expect to contribute an additional $6.3 million to our pension plans and $8.9 million to our other postretirement benefit plans during the remainder of 2015, dependent upon various factors affecting us, including our liquidity position and possible tax law changes. In 2015, contributions of $7.0 million will be funded through a transfer of assets from the rabbi trust for certain nonqualified pension plans, of which $2.2 million was paid to participants through March 31, 2015. See the discussion below in regard to the triggering of the full funding of the rabbi trust.

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. As a result, $132.2 million, consisting of cash and exchange-traded funds, was moved to the rabbi trust during 2014 and was included in other long-term assets on the balance sheet as of March 31, 2015, and December 31, 2014. In 2015, a portion of the amounts contributed to the rabbi trust in 2014 were used to fund participant's benefits under the deferred compensation program and certain nonqualified pension plans, as discussed above. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on the merger.

Note 14—Stock-Based Compensation

The following table reflects the stock-based compensation expense and the related deferred income tax benefit recognized in income for the three months ended March 31:

	Three Months Ended March 31	
(Millions)	2015	2014
Stock options	$—	$0.3
Performance stock rights	0.6	0.5
Restricted share units	3.4	2.5
Nonemployee director deferred stock units	0.2	0.2
Total stock-based compensation expense	$4.2	$3.5
Deferred income tax benefit	$1.7	$1.4

No stock-based compensation cost was capitalized during the three months ended March 31, 2015, and 2014.

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Stock Options

The weighted-average fair value per stock option granted during the three months ended March 31, 2014, was $6.70. No stock options were granted during 2015.

A summary of stock option activity for the three months ended March 31, 2015, and information related to outstanding and exercisable stock options at March 31, 2015, is presented below:

	Stock Options	Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2014	134,017	$ 54.31		
Exercised	(45,297)	53.32		
Outstanding at March 31, 2015	88,720	$ 54.81	6.6	$1.5
Exercisable at March 31, 2015	53,057	$ 54.84	5.9	$0.9

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they all exercised their options on March 31, 2015. This is calculated as the difference between our closing stock price on March 31, 2015, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the three months ended March 31, 2015, and 2014 was not significant. Cash received from option exercises during the three months ended March 31, 2015, was $2.7 million, and was not significant for the three months ended March 31, 2014.

Due to the accelerated vesting of all unvested stock options held by active employees in October 2014, all compensation expense related to outstanding stock options has been recognized.

Performance Stock Rights

The fair values of performance stock rights are estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. The expected stock price volatility is estimated using two to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at March 31, 2015:

Risk-free interest rate	0.42% – 0.63%
Expected dividend yield	5.25% – 5.33%
Expected volatility	18% – 19%

A summary of the activity for the three months ended March 31, 2015, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value *
Outstanding at December 31, 2014	68,263	$ 58.54
Distributed	(38,639)	78.37
Adjustment for payout	12,751	78.37
Outstanding at March 31, 2015	42,375	$ 46.42

* Reflects the weighted-average fair value used to measure equity awards. Equity awards are measured using the grant date fair value or the fair value on the modification date.

The weighted-average grant date fair value of performance stock rights awarded during the three months ended March 31, 2014, was $44.28 per performance stock right. No performance stock rights were granted during 2015.

A summary of the activity for the three months ended March 31, 2015, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights	
Outstanding at December 31, 2014	170,308	
Distributed	(1,746	)
Adjustment for payout	831	
Outstanding at March 31, 2015	169,393	

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of March 31, 2015, was $106.95 per performance stock right.

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The total intrinsic value of shares distributed during the three months ended March 31, 2015, was $3.1 million. The actual tax benefit realized for the tax deductions from the distribution of shares during the three months ended March 31, 2015, was not significant. No shares of common stock were distributed for performance stock rights during the three months ended March 31, 2014, because the performance percentage was below the threshold payout level for those rights that were eligible for distribution.

As of March 31, 2015, $3.3 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.4 years.

Restricted Share Units

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the three months ended March 31, 2015, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2014	427,305	$ 54.45
Granted	224,784	77.17
Dividend equivalents	4,437	65.31
Vested and released	(166,545)	53.49
Forfeited	(530)	52.35
Outstanding at March 31, 2015	489,451	$ 65.31

The weighted-average grant date fair value of restricted share units awarded during the three months ended March 31, 2015, and 2014, was $77.17 and $55.23 per unit, respectively.

The total intrinsic value of restricted share unit awards vested and released during the three months ended March 31, 2015, and 2014, was $12.8 million and $11.1 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted share units during the three months ended March 31, 2015, and 2014, was $5.1 million and $4.4 million, respectively.

As of March 31, 2015, $20.4 million of compensation cost related to unvested and outstanding restricted share units was expected to be recognized over a weighted-average period of 2.2 years.

Note 15—Common Equity

We had no changes to issued common stock during the three months ended March 31, 2015. Under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we cannot issue shares of our common stock.

The following table provides a summary of common stock activity to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans:

Period	Method of meeting requirements
Beginning 02/05/14	Purchasing shares on the open market
02/05/2013 – 02/04/2014	Issued new shares

The following table reconciles common shares issued and outstanding:

	March 31, 2015		December 31, 2014	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,963,091		79,963,091	

Less:				
Deferred compensation rabbi trust	428,920	$48.73	428,920	$48.73
Total common shares outstanding	79,534,171		79,534,171	

* Based on our stock price on the day the shares entered the deferred compensation rabbi trust. Shares paid out of the trust are valued at the average cost of shares in the trust.

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Earnings Per Share

Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for shares we are obligated to issue under the deferred compensation and restricted share unit plans. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, restricted share units, unvested director deferred stock units, and certain shares issuable under the deferred compensation plan. As the obligation for certain shares issuable under the deferred compensation plan is accounted for as a liability, the numerator is adjusted for any changes in income or loss that would have resulted had it been accounted for as an equity instrument during the period.

The following table reconciles our computation of basic and diluted earnings per share:

	Three Months Ended March 31	
(Millions, except per share amounts)	2015	2014
Numerator:		
Net income from continuing operations	$131.2	$140.2
Discontinued operations, net of tax	(0.9)	12.9
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	—	0.1
Net income attributed to common shareholders — basic	$129.5	$152.4
Effect of dilutive securities		
Deferred compensation	(0.6)	—
Net income attributed to common shareholders — diluted	$128.9	$152.4
Denominator:		
Average shares of common stock — basic	80.2	80.2
Effect of dilutive securities		
Stock-based compensation	0.4	0.3
Deferred compensation	0.2	—
Average shares of common stock — diluted	80.8	80.5
Earnings per common share		
Basic	$1.61	$1.90
Diluted	1.60	1.89

The calculation of diluted earnings per share excluded the following weighted-average outstanding securities that had an anti-dilutive effect:

	Three Months Ended March 31	
(Millions)	2015	2014
Stock-based compensation	—	0.7
Deferred compensation	—	0.3

Dividend Restrictions

Our ability as a holding company to pay dividends 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 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%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of their outstanding debt obligations.

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As of March 31, 2015, total restricted net assets of consolidated subsidiaries were $1,872.6 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $158.1 million at March 31, 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%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of outstanding debt obligations. At March 31, 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.

Under the merger agreement with Wisconsin Energy, we may not declare or pay any dividends or distributions on our common stock other than the regular quarterly dividend of $0.68 per share.

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

Capital Transactions with Subsidiaries

During the three months ended March 31, 2015, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
ITF [1]	$ —	$ —	$ 1.0
MERC	—	10.5	—
MGU	—	13.0	—
NSG [1]	7.5	—	—
WPS	28.8	—	—
WPS Investments, LLC [2]	13.7	—	1.7
Total	$ 50.0	$ 23.5	$ 2.7

(1) ITF and NSG are direct wholly owned subsidiaries of PELLC. As a result, they make distributions to PELLC, and receive equity contributions from PELLC. Subject to applicable law, PELLC does not have any dividend restrictions or limitations on distributions to us.

(2) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us and WPS. At March 31, 2015, the ownership interest held by us and WPS was 89.06% and 10.94%, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2015, all equity contributions to WPS Investments, LLC were made solely by us.

Note 16—Accumulated Other Comprehensive Loss

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

Three Months Ended March 31, 2015	Accumulated Other
(Millions)	

	Cash Flow Hedges	Defined Benefit Plans	Comprehensive Loss
Beginning balance at December 31, 2014	$(3.2)	$(24.4)	$(27.6)
Amounts reclassified out of accumulated other comprehensive loss	0.1	0.7	0.8
Ending balance at March 31, 2015	$(3.1)	$(23.7)	$(26.8)

Three Months Ended March 31, 2014 (Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Beginning balance at December 31, 2013	$(3.1)	$(20.1)	$(23.2)
Other comprehensive loss before reclassifications	—	(0.1)	(0.1)
Amounts reclassified out of accumulated other comprehensive loss	(0.6)	0.3	(0.3)
Net current period other comprehensive (loss) income	(0.6)	0.2	(0.4)
Ending balance at March 31, 2014	$(3.7)	$(19.9)	$(23.6)

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The following table shows the reclassifications out of accumulated other comprehensive loss:

(Millions)	Amount Reclassified Three Months Ended March 31 2015	2014	Affected Line Item in the Statements of Income
Losses (gains) on cash flow hedges			
Interest rate hedges	$0.2	$0.3	Interest expense
	0.1	0.9	Tax expense
	0.1	(0.6)	Net of tax
Defined benefit plans			
Amortization of prior service costs (credits)	0.3	(0.1)	*
Amortization of net actuarial losses	0.9	0.7	*
	1.2	0.6	Total before tax
	0.5	0.3	Tax expense
	0.7	0.3	Net of tax
Total reclassifications	$0.8	$(0.3)	

* These items are included in the computation of net periodic benefit cost. See Note 13, Employee Benefit Plans, for more information.

Note 17—Variable Interest Entities

AMP Trillium, LLC

In 2012, ITF formed AMP Trillium, LLC as a joint venture with AMP Americas, LLC. ITF owns 30% and AMP Americas, LLC owns 70% of the joint venture. This joint venture was established to own and operate compressed natural gas (CNG) fueling stations. ITF and AMP Americas, LLC restructured AMP Trillium, LLC in April 2014. We have determined that this joint venture is a variable interest entity but that consolidation is not required since we are not its primary beneficiary, as we do not have the power to direct the activities that most significantly impact its economic performance. We instead account for this variable interest entity as an equity method investment. At March 31, 2015, and December 31, 2014, the assets and liabilities on our balance sheets related to our involvement with this variable interest entity consisted of receivables, payables, and an equity investment. The following table shows the significant assets and liabilities recorded on our balance sheets related to AMP Trillium, LLC:

(Millions)	March 31, 2015	December 31, 2014
Assets		
Accounts receivable and accrued unbilled revenues	$12.1	$9.5
Other current assets [(1)]	2.0	2.0
Investment in AMP Trillium, LLC	5.4	5.5
Other long-term assets [(1)]	11.3	11.8
Liabilities		
Accounts payable	2.7	1.4
Other current liabilities [(2)]	2.1	2.0

(1) Relates to notes receivable due from AMP Trillium, LLC.

(2) Relates to deferred revenue from the sale of CNG fueling stations to AMP Trillium, LLC.

Our maximum exposure to loss as a result of involvement with this variable interest entity was not significant.

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EVO Trillium, LLC

In 2013, ITF formed EVO Trillium, LLC as a joint venture with Environmental Alternative Fuels, LLC. ITF owns 15% and Environmental Alternative Fuels, LLC owns 85% of the joint venture. This joint venture was established to own and operate CNG fueling stations. We have determined that this joint venture is a variable interest entity but that consolidation is not required since we are not its primary beneficiary, as we do not have the power to direct the activities that most significantly impact its economic performance. We instead account for this variable interest entity as an equity method investment. At March 31, 2015, and December 31, 2014, the assets and liabilities on our balance sheets related to our involvement with this variable interest entity consisted of receivables and payables. The following table shows the significant assets recorded on our balance sheets related to EVO Trillium, LLC:

(Millions)	March 31, 2015	December 31, 2014
Assets		
Accounts receivable and accrued unbilled revenues	$7.6	$8.8
Other current assets *	1.1	0.5
Other long-term assets *	4.0	1.7

*Primarily relates to notes receivable due from EVO Trillium, LLC.

Our maximum exposure to loss as a result of involvement with this variable interest entity was not significant.

Note 18—Risk Management Activities

Utility 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. The electric utility segment uses FTRs to manage electric transmission congestion costs. The natural gas and electric utility segments use financial derivative contracts to manage the risks associated with the market price volatility of natural gas supply costs. In addition, IBS enters into financial derivative contracts on behalf of the utilities to manage the cost of gasoline and diesel fuel used by utility vehicles.

The following tables show our assets and liabilities from risk management activities at the utilities and IBS:

		March 31, 2015	
(Millions)	Balance Sheet Presentation *	Assets from Risk Management Activities	Liabilities from Risk Management Activities
Natural gas contracts	Other current	$0.5	$28.0
Natural gas contracts	Other long-term	0.6	5.7
FTRs	Other current	0.7	0.1
Petroleum product contracts	Other current	—	2.1
Coal contracts	Other current	—	4.3
Coal contracts	Other long-term	—	3.1
	Other current	1.2	34.5
	Other long-term	0.6	8.8
Total		$1.8	$43.3

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

	December 31, 2014	
(Millions)	Assets from	Liabilities from

	Balance Sheet Presentation *	Risk Management Activities	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.

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

(Millions)	March 31, 2015 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements	$1.8	$1.2	$0.6
Derivative assets not subject to master netting or similar arrangements	—		—
Total risk management assets	$1.8		$0.6
Derivative liabilities subject to master netting or similar arrangements	$35.9	$5.5	$30.4
Derivative liabilities not subject to master netting or similar arrangements	7.4		7.4
Total risk management liabilities	$43.3		$37.8

(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.

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)	March 31, 2015	December 31, 2014
Cash collateral provided to others: *		
Related to contracts under master netting or similar arrangements	$8.9	$11.6
Other	1.1	1.1

*Cash collateral provided to others is reflected in other current assets.

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 March 31, 2015, and December 31, 2014, was $31.4 million and $31.3 million, respectively. At March 31, 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 March 31, 2015, and at December 31, 2014, we would have been required to post collateral of $30.1 million and $27.1 million, respectively.

The notional volumes of outstanding derivative contracts at the utilities and IBS were as follows:

	March 31, 2015		December 31, 2014	
(Millions)	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (therms)	669.0	N/A	1,860.0	N/A
FTRs (kilowatt-hours)	N/A	2,111.1	N/A	4,287.7
Petroleum products (barrels)	0.1	N/A	0.1	N/A
Coal (tons)	2.6	N/A	3.0	N/A

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The table below shows the unrealized gains (losses) recorded related to derivative contracts at the utilities and IBS:

		Three Months Ended March 31	
(Millions)	Financial Statement Presentation	2015	2014
Natural gas	Balance Sheet — Regulatory assets (current)	$10.9	$0.9
Natural gas	Balance Sheet — Regulatory assets (long-term)	(0.6)	(0.2)
Natural gas	Balance Sheet — Regulatory liabilities (current)	(1.5)	3.4
Natural gas	Balance Sheet — Regulatory liabilities (long-term)	0.1	(0.4)
Natural gas	Income Statement — Operating and maintenance expense	(0.1)	0.2
FTRs	Balance Sheet — Regulatory assets (current)	0.2	0.1
FTRs	Balance Sheet — Regulatory liabilities (current)	(0.4)	(0.1)
Petroleum	Balance Sheet — Regulatory assets (current)	0.4	—
Petroleum	Income Statement — Operating and maintenance expense	0.4	—
Coal	Balance Sheet — Regulatory assets (current)	(2.6)	0.2
Coal	Balance Sheet — Regulatory assets (long-term)	(2.0)	0.4
Coal	Balance Sheet — Regulatory liabilities (long-term)	—	1.6

Note 19—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.

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, which is part of the corporate treasury function. 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.

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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:

	March 31, 2015			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Natural gas contracts	$0.1	$1.0	$—	$1.1
Financial transmission rights (FTRs)	—	—	0.7	0.7
Total Risk Management Assets	$0.1	$1.0	$0.7	$1.8
Investment in exchange-traded funds	$112.3	$—	$—	$112.3
Liabilities				
Risk Management Liabilities				
Natural gas contracts	$2.3	$31.4	$—	$33.7
Petroleum product contracts	2.1	—	—	2.1
FTRs	—	—	0.1	0.1
Coal contracts	—	1.2	6.2	7.4
Total Risk Management Liabilities	$4.4	$32.6	$6.3	$43.3

	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 18, Risk Management Activities, for more information.

There were no transfers between the levels of the fair value hierarchy during the three months ended March 31, 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 March 31, 2015:

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
FTRs	$ 0.7	$ 0.1	Market-based	Forward market prices ($/megawatt-month) (1)	$159.42
Coal contracts	—	6.2	Market-based	Forward market prices ($/ton) (2)	$9.70 – $12.39

(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 March 31, 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	—	(1.2)	—	(1.2)
Net unrealized losses recorded as regulatory assets or liabilities	—	(0.2)	(4.3)	(4.5)
Settlements	6.6	0.1	0.3	7.0
Balance at the end of the period	$—	$0.6	$(6.2)	$(5.6)

Three Months Ended March 31, 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	0.7	—	0.7
Net unrealized gains recorded as regulatory assets or liabilities	—	2.2	2.2
Purchases	(0.1)	—	(0.1)
Settlements	(1.3)	0.6	(0.7)
Balance at the end of the period	$0.5	$0.3	$0.8

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:

	March 31, 2015		December 31, 2014	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,081.3	$3,328.0	$3,081.3	$3,271.4
Preferred stock of subsidiary	51.1	52.3	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.

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 20—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 the expiration of a 2015 customer refund related to decoupling, increased operating and maintenance costs, and general inflation.

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 million. In addition, 2015 rates include approximately $9 million of lower refunds to customers related to decoupling over-collections. In 2015 rates, WPS is refunding approximately $4 million to customers related to 2013 decoupling over-collections compared with refunding approximately $13 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 million year-over-year negative impact of decoupling refunds to and collections from customers. In 2015 rates, WPS is refunding approximately $8 million to customers related to 2013 decoupling over-collections compared with recovering approximately $8 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 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 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.

Michigan

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

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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.

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, which authorized retail natural gas rates for both PGL and 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 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 January 2015, the Citizens Utility Board filed to withdraw its appeal, and the Illinois Attorney General requested an extension of the briefing schedule.

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, $4.7 million is expected to be refunded to customers beginning in June 2015, and is recorded as a regulatory liability.

Note 21—Segments of Business

At March 31, 2015, we had four segments related to our continuing operations and one segment related to the discontinued operations of IES's retail energy business. Our reportable segments are described below.

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

on the sale of UPPCO.

- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- The IES segment includes the nonregulated energy operations of IES's retail energy business. Since we sold IES's retail energy business in November 2014, this segment only includes discontinued operations. See Note 4, Dispositions, for more information on the sale of IES's retail energy business. The remaining energy asset business, PDI, was reclassified to the holding company and other segment.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company, ITF, PDI, and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS.

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The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended March 31, 2015								
External revenues	$839.5	$295.8	$ —	$ 1,135.3	$—	$27.9	$ —	$ 1,163.2
Intersegment revenues	2.6	—	—	2.6	—	0.2	(2.8)	—
Depreciation and amortization expense	40.6	25.0	—	65.6	—	9.2	(0.1)	74.7
Earnings from equity method investments	—	—	17.0	17.0	—	0.5	—	17.5
Miscellaneous income	0.7	2.8	—	3.5	—	5.1	(2.0)	6.6
Interest expense	14.3	10.9	—	25.2	—	15.0	(2.0)	38.2
Provision (benefit) for income taxes	65.9	16.4	6.7	89.0	—	(10.1)	—	78.9
Net income (loss) from continuing operations	97.8	28.6	10.3	136.7	—	(5.5)	—	131.2
Discontinued operations	—	—	—	—	(0.8)	(0.1)	—	(0.9)
Preferred stock dividends of subsidiary	(0.1)	(0.7)	—	(0.8)	—	—	—	(0.8)
Net income (loss) attributed to common shareholders	97.7	27.9	10.3	135.9	(0.8)	(5.6)	—	129.5

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	IES	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended March 31, 2014								
External revenues	$1,267.6	$349.2	$ —	$ 1,616.8	$—	$21.2	$ —	$ 1,638.0
Intersegment revenues	4.4	—	—	4.4	—	0.4	(4.8)	—
Depreciation and amortization expense	36.4	25.6	—	62.0	—	8.7	(0.1)	70.6
Earnings from equity method investments	—	—	22.5	22.5	—	0.4	—	22.9
Miscellaneous income	0.3	3.5	—	3.8	—	5.3	(3.3)	5.8
Interest expense	13.4	11.7	—	25.1	—	17.1	(3.3)	38.9
Provision (benefit) for income taxes	66.7	18.1	8.8	93.6	—	(11.7)	—	81.9
	99.2	31.8	13.7	144.7	—	(4.5)	—	140.2

Net income (loss) from continuing operations								
Discontinued operations	—	—	—	—	13.0	(0.1)	—	12.9
Preferred stock dividends of subsidiary	(0.1)	(0.7)	—	(0.8)	—	—	—	(0.8)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	99.1	31.1	13.7	143.9	13.0	(4.5)	—	152.4

Note 22—New Accounting Pronouncements

Recently Issued Accounting Guidance Not Yet Effective

In April 2015 the FASB issued ASU 2015-05, "Customer’s Accounting for Fees Paid in a Cloud Computing Arrangement." The ASU provides guidance for determining whether a cloud computing arrangement includes a software license, which should be accounted for consistent with the acquisition of other software licenses. Cloud computing arrangements that do not include a software license should be accounted for as service contracts. This guidance may be applied either prospectively to new cloud computing arrangements, or retrospectively 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 that the adoption of this standard will have on our financial statements.

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.

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In February 2015 the FASB issued ASU 2015-02, "Amendments to the Consolidation Analysis." The guidance focuses on the consolidation evaluation for companies that are required to evaluate whether they should consolidate certain legal entities. It places more emphasis on risk of loss when determining a controlling financial interest and amends the guidance for assessing how relationships of related parties affect the consolidation analysis of variable interest entities. 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 January 2015 the FASB issued ASU 2015-01, "Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items." This guidance eliminates the disclosure of extraordinary items, net of tax, in the income statement after income from continuing operations. The guidance is effective for us for the reporting period ending March 31, 2016. We do not currently have any extraordinary items presented on the income statements. However, this guidance will eliminate the need for us to further assess whether unusual and infrequently occurring transactions qualify as extraordinary items in the future.

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 is currently effective for us for the reporting period ending March 31, 2017; however, in April 2015 the FASB issued an exposure draft proposing to delay the effective date for one year. 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

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.

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Three Months Ended March 31 2015	2014	Change in 2015 Over 2014
Natural gas utility operations	$97.7	$99.1	(1.4)%
Electric utility operations	27.9	31.1	(10.3)%
Electric transmission investment	10.3	13.7	(24.8)%
IES's retail energy business - discontinued operations	(0.8)	13.0	N/A
Holding company and other operations	(5.6)	(4.5)	24.4 %
Net income attributed to common shareholders	$129.5	$152.4	(15.0)%
Basic earnings per share	$1.61	$1.90	(15.3)%
Diluted earnings per share	$1.60	$1.89	(15.3)%
Average shares of common stock			
Basic	80.2	80.2	— %
Diluted	80.8	80.5	0.4 %

First Quarter 2015 Compared with First Quarter 2014

The $22.9 million decrease in our earnings was driven by:

- A $13.8 million after-tax decrease in earnings from discontinued operations related to IES's retail energy business. See Note 4, Dispositions, for more information.

- An approximate $12 million after-tax decrease in margins at our existing utilities due to variances related to sales volumes, net of decoupling, driven by warmer quarter-over-quarter weather. Although weather was colder than normal in the first quarter of 2015, it was warmer than the extreme cold of 2014.

- An approximate $4 million after-tax decrease in earnings due to the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $3.4 million after-tax decrease in earnings from our approximate 34% ownership interest in ATC. 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. The reserve included an after-tax adjustment of

$2.9 million related to prior years due to a revision to the estimated refund.

These decreases were partially offset by an $11.0 million after-tax decrease in operating expenses at our existing utilities, excluding items directly offset in margins, driven by lower repairs and maintenance expense.

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Natural Gas Utility Segment Operations

	Three Months Ended March 31		Change in 2015 Over
(Millions, except degree days)	2015	2014	2014
Revenues	$842.1	$1,272.0	(33.8)%
Purchased natural gas costs	447.1	830.4	(46.2)%
Margins	395.0	441.6	(10.6)%
Operating and maintenance expense	165.6	215.4	(23.1)%
Depreciation and amortization expense	40.6	36.4	11.5 %
Taxes other than income taxes	11.5	10.8	6.5 %
Operating income	177.3	179.0	(0.9)%
Miscellaneous income	0.7	0.3	133.3 %
Interest expense	14.3	13.4	6.7 %
Other expense	(13.6)	(13.1)	3.8 %
Income before taxes	$163.7	$165.9	(1.3)%
Retail throughput in therms			
Residential	793.2	927.2	(14.5)%
Commercial and industrial	255.7	301.4	(15.2)%
Other	18.7	23.9	(21.8)%
Total retail throughput in therms	1,067.6	1,252.5	(14.8)%
Transport throughput in therms			
Residential	143.2	135.4	5.8 %
Commercial and industrial	600.3	618.9	(3.0)%
Total transport throughput in therms	743.5	754.3	(1.4)%
Total throughput in therms	1,811.1	2,006.8	(9.8)%
Weather			
Average actual heating degree days	3,779	4,174	(9.5)%
Average normal heating degree days	3,425	3,371	1.6 %

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 36% decrease in the average per-unit cost of natural gas sold during the three months ended March 31, 2015, which had no impact on margins.

First Quarter 2015 Compared with First Quarter 2014

Margins

Natural gas utility segment margins decreased $46.6 million, driven by:

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A $39.1 million decrease in margins related to certain riders at NSG and PGL and certain energy efficiency programs at four of our natural gas utilities. This decrease was offset by an equal decrease in operating expenses, resulting in no impact on earnings.

Our natural gas utilities recovered $24.5 million less from customers for energy efficiency programs at MERC, MGU, NSG, and PGL in 2015.

PGL and NSG recovered $8.4 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.

PGL and NSG recovered a net $6.2 million less from their customers for environmental cleanup costs at their former manufactured gas plant sites. Recovery rates at PGL were lower due to a decrease in remediation costs, net of insurance settlements received, and sales volumes were lower at both PGL and NSG. See Note 11, Commitments and Contingencies, for more information about the manufactured gas plant sites.

- An approximate $14 million decrease in margins from the combined effect of warmer weather quarter over quarter, lower weather-normalized volumes, and the partially offsetting impact of our decoupling mechanisms at MERC, MGU, NSG, and PGL. Margins for certain customer classes in both years, including all of WPS's customers, were sensitive to volume variances as they were not covered by decoupling mechanisms. See Note 20, Regulatory Environment, for more information on our decoupling mechanisms.

- These decreases were partially offset by an approximate $6 million net increase in margins due to rate orders. See Note 20, Regulatory Environment, for more information.

The rate increases at NSG and PGL, effective January 28, 2015, and updated effective February 26, 2015, had an approximate $19 million positive impact on margins.

Increased revenues at PGL for its Qualifying Infrastructure Plant rider had an approximate $2 million positive impact on margins.

These increases were partially offset by an approximate $15 million decrease in margins at WPS due to a rate decrease, effective January 1, 2015, including an approximate $5 million negative impact due to rate design changes. The 2015 rate order changed our rate design by increasing fixed charges but lowering 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 20, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment decreased $1.7 million. This decrease was driven by the $46.6 million decrease in margins discussed above, partially offset by a $44.9 million decrease in operating expenses.

The decrease in operating expenses was primarily due to:

- A $24.8 million net decrease in energy efficiency program expenses at our natural gas utilities. For the majority of this decrease in expenses, margins decreased by an equal amount, resulting in no impact on earnings.

- A $9.3 million decrease in bad debt expense, driven by lower natural gas costs in 2015 and a decrease in sales volumes. The majority of the decrease in bad debt expense was related to PGL and NSG and had no impact on earnings since it was offset by lower rates through a rider mechanism, resulting in lower margins.

- A $6.0 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 net decrease in expenses was more than offset by a related decrease in margins.

- A $4.5 million decrease in natural gas distribution costs, primarily at PGL. The decrease in costs at PGL was driven by reduced repair and maintenance activity.

These decreases were partially offset by:

- A $4.2 million increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the AMRP at PGL.

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Electric Utility Segment Operations

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 4, Dispositions, for more information.

(Millions, except degree days)	Three Months Ended March 31 2015	2014	Change in 2015 Over 2014
Revenues	$295.8	$349.2	(15.3)%
Fuel and purchased power costs	115.1	136.7	(15.8)%
Margins	180.7	212.5	(15.0)%
Operating and maintenance expense	91.7	116.0	(20.9)%
Depreciation and amortization expense	25.0	25.6	(2.3)%
Taxes other than income taxes	10.9	12.8	(14.8)%
Operating income	53.1	58.1	(8.6)%
Miscellaneous income	2.8	3.5	(20.0)%
Interest expense	10.9	11.7	(6.8)%
Other expense	(8.1)	(8.2)	(1.2)%
Income before taxes	$45.0	$49.9	(9.8)%
Sales in kilowatt-hours			
Residential	762.1	898.3	(15.2)%
Commercial and industrial	1,969.1	2,077.9	(5.2)%
Wholesale	635.5	571.2	11.3 %
Opportunity sales	302.0	113.6	165.8 %
Other	9.2	10.6	(13.2)%
Total sales in kilowatt-hours	3,677.9	3,671.6	0.2 %
Weather			
WPS:			
Actual heating degree days	3,946	4,515	(12.6)%
Normal heating degree days	3,662	3,646	0.4 %

Electric utility margins are defined as electric utility operating revenues less fuel and purchased power costs. Management believes that electric utility margins provide a more meaningful basis for evaluating electric utility operations than electric utility 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.

First Quarter 2015 Compared with First Quarter 2014

Margins

Electric utility segment margins decreased $31.8 million, driven by:

- An approximate $22 million decrease in margins related to the sale of UPPCO at the end of August 2014. See Note 4, Dispositions, for more information.

- An approximate $5 million decrease in margins at WPS related to sales volume variances. Margins from residential customers decreased, driven by the warmer weather in 2015.

- An approximate $4 million decrease in margins at WPS related to the PSCW rate order, 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 20, Regulatory Environment, for more information.

Margins at WPS decreased approximately $6 million as a result of the PSCW rate order and rate design.

Margins at WPS were negatively impacted by approximately $1 million due to higher fuel costs not included in the fuel rule recovery mechanism. The majority of this was higher fly ash disposal costs in 2015.

These decreases in margins were partially offset by an increase of approximately $3 million related to fuel and purchased power cost over-collections at WPS in 2015, compared with under-collections 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.

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Operating Income

Operating income at the electric utility segment decreased $5.0 million. The decrease was primarily driven by the $31.8 million decrease in margins discussed above, partially offset by a $26.8 million decrease in operating expenses.

The decrease in operating expenses was driven by:

- A $14.3 million decrease in operating expenses related to the sale of UPPCO at the end of August 2014. See Note 4, Dispositions, for more information.

- A $7.9 million decrease in maintenance expense at WPS, primarily due to a planned major outage at the Pulliam plant in 2014, as well as lower maintenance at our jointly-owned plants in 2015.

- A $2.5 million decrease in asset usage charges from IBS.

- A $1.6 million net decrease in employee benefit costs at WPS, driven by amortization in 2014 of a prior year deferral of certain employee benefit costs.

These decreases were partially offset by a $1.5 million increase in depreciation and amortization expense at WPS, mainly due to the installation of scrubbers at the Columbia plant in April 2014.

Electric Transmission Investment Segment Operations

(Millions)	Three Months Ended March 31 2015	2014	Change in 2015 Over 2014
Earnings from equity method investment	$17.0	$22.5	(24.4)%

First Quarter 2015 Compared with First Quarter 2014

Earnings from our approximate 34% ownership interest in ATC decreased $5.5 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. The reserve included an adjustment of $4.8 million related to prior years due to a revision to the estimated refund.

Holding Company and Other Segment Operations

(Millions)	Three Months Ended March 31 2015	2014	Change in 2015 Over 2014
Operating loss	$(6.2)	$(4.8)	29.2%
Other expense	(9.4)	(11.4)	(17.5)%
Loss before taxes	$(15.6)	$(16.2)	(3.7)%

First Quarter 2015 Compared with First Quarter 2014

Operating Loss

Operating loss at the holding company and other segment increased $1.4 million, driven by a $3.3 million decrease in IBS's return on capital charged to the utilities. This operating loss increase was partially offset by an approximate $2 million positive quarter-over-quarter impact from IBS costs previously charged to IES's retail energy business that were allocated to the holding company and other segment in 2014. These variances had no impact on our consolidated earnings as they were offset in the other segments.

Other Expense

Other expense at the holding company and other segment decreased $2.0 million. The decrease was primarily due to lower interest expense on long-term debt, driven by the repayment of $100.0 million of Senior Notes in June 2014.

Provision for Income Taxes

	Three Months Ended March 31	
	2015	2014
Effective tax rate	37.6 %	36.9 %

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

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Discontinued Operations

(Millions)	Three Months Ended March 31 2015	2014	Change in 2015 Over 2014
Discontinued operations, net of tax	$(0.9)	$12.9	N/A

First Quarter 2015 Compared with First Quarter 2014

Earnings from discontinued operations, net of tax, decreased $13.8 million to a net loss in the first quarter of 2015. This decrease was driven by the sale of IES's retail energy business in November 2014. During the first quarter of 2014, we recognized after-tax earnings from discontinued operations of $13.0 million related to the operations of IES's retail energy business. The loss from discontinued operations in the first quarter of 2015 was primarily the result of a working capital adjustment related to the sale of IES's retail energy business. See Note 4, 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 equity and debt capital markets, and available borrowing capacity under existing credit facilities. 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 three months ended March 31, 2015, net cash provided by operating activities was $524.2 million, compared with $269.7 million during the same period in 2014. The $254.5 million increase in net cash provided by operating activities was driven by:

- A $1,177.2 million increase in cash related to lower costs of natural gas, fuel, and purchased power in 2015, mainly due to the sales of the IES retail energy business in November 2014 and UPPCO in August 2014. See Note 4, Dispositions, for more information. Lower commodity prices and warmer weather in the first quarter of 2015 also contributed to the increase in cash.

- A $165.1 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 4, Dispositions, for more information. In addition, the utilities had lower repairs and maintenance costs in 2015.

- A $65.7 million decrease in contributions to pension and other postretirement benefit plans.

- A $37.6 million increase in cash driven by the elimination of collateral requirements for IES in 2015. We sold IES's retail energy business in November 2014. See Note 4, Dispositions, for more information.

- A $16.4 million increase in cash from customer prepayments and credit balances. In 2015, customer prepayments grew during the warmer winter.

These increases in cash were partially offset by:

- A $1,166.9 million decrease in cash collections from customers, mainly due to the sales of the IES retail energy business in November 2014 and UPPCO in August 2014. See Note 4, Dispositions, for more information. Lower commodity prices and warmer weather in the first quarter of 2015 also contributed to the decrease in cash collections.

- An $11.6 million decrease in cash received from income taxes, primarily driven by a lower federal income tax refund received in 2015 compared with 2014, partially offset by a state income tax refund received in 2015.

- A $9.0 million increase in cash used for environmental remediation activities.

Investing Cash Flows

During the three months ended March 31, 2015, net cash used for investing activities was $197.5 million, compared with $163.3 million during the same period in 2014. The $34.2 million increase in net cash used for investing activities was primarily driven by a $49.2 million increase in cash used for capital expenditures (discussed below). This increase in cash used was partially offset by the receipt of $10.9 million of cash from the rabbi trust to fund deferred compensation and nonqualified pension plan payments in the first quarter of 2015. The cash outflow related to the payments is in the operating activities section of the statement of cash flows.

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Capital Expenditures

Capital expenditures by business segment for the three months ended March 31 were as follows:

Reportable Segment (millions)	2015	2014	Change in 2015 Over 2014
Natural gas utility	$106.3	$68.2	$38.1
Electric utility	70.1	55.7	14.4
IES	—	0.7	(0.7)
Holding company and other	32.4	35.0	(2.6)
Integrys Energy Group consolidated	$208.8	$159.6	$49.2

The increase in capital expenditures at the natural gas utility segment in 2015 compared with 2014 was primarily due to work on the AMRP at PGL.

The increase in capital expenditures at the electric utility segment in 2015 compared with 2014 was primarily due to the ReACT™ project at Weston 3 and the System Modernization and Reliability Project.

Financing Cash Flows

During the three months ended March 31, 2015, net cash used for financing activities was $258.3 million, compared with $72.1 million during the same period in 2014. The $186.2 million increase in cash used for financing activities was driven by:

- A $180.2 million increase in net repayments of commercial paper in 2015.