WORLD FUEL SERVICES CORP
Form 8-K
February 09, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 8-K

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(D) OF

THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported): February 9, 2012

WORLD FUEL SERVICES CORPORATION
(Exact name of registrant as specified in its charter)

Florida	**1-9533**	**59-2459427**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

9800 N.W. 41st Street, Suite 400

Miami	**33178**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(305) 428-8000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01. Regulation FD Disclosure

On February 9, 2012, World Fuel Services Corporation (the "Company") issued a press release announcing that a conference call has been scheduled on Thursday, February 23, 2012 at 5:00PM Eastern Time to discuss the Company's fourth quarter results. A copy of the press release is attached hereto as Exhibit 99.1.

This information and the information contained in Exhibit 99.1 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Exchange Act, except as may be expressly set forth by specific reference in any such filing.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits

Exhibit No.	Description
99.1	Press Release, dated February 9, 2012.

SIGNATURE

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

Date: February 9, 2012 **World Fuel Services Corporation**

/s/ R. Alexander Lake
R. Alexander Lake
Senior Vice President, General
Counsel and
Corporate Secretary

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Acronyms Used in this Quarterly Report on Form 10-Q

ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
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
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, 2013, 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 our regulated businesses;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- 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;
- 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;
- 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 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 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;
- The ability to use tax credit and loss 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;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed timely or within budgets;
- 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;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;

- 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 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)	2014	2013
Utility revenues	$1,616.7	$1,123.8
Nonregulated revenues	1,308.2	554.4
Total revenues	2,924.9	1,678.2
Utility cost of fuel, natural gas, and purchased power	960.2	565.1
Nonregulated cost of sales	1,247.5	436.8
Operating and maintenance expense	364.6	295.1
Depreciation and amortization expense	71.3	60.9
Taxes other than income taxes	28.1	27.2
Operating income	253.2	293.1
Earnings from equity method investments	22.9	22.3
Miscellaneous income	6.0	5.7
Interest expense	39.1	29.3
Other expense	(10.2)	(1.3)
Income before taxes	243.0	291.8
Provision for income taxes	89.8	109.6
Net income from continuing operations	153.2	182.2
Discontinued operations, net of tax	(0.1)	6.1
Net income	153.1	188.3
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	0.1	—
Net income attributed to common shareholders	$152.4	$187.5
Average shares of common stock		
Basic	80.2	78.7
Diluted	80.5	79.3
Earnings per common share (basic)		
Net income from continuing operations	$1.90	$2.30
Discontinued operations, net of tax	—	0.08
Earnings per common share (basic)	$1.90	$2.38
Earnings per common share (diluted)		
Net income from continuing operations	$1.89	$2.29
Discontinued operations, net of tax	—	0.08
Earnings per common share (diluted)	$1.89	$2.37

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)

	Three Months Ended March 31	
(Millions)	2014	2013
Net income	$153.1	$188.3
Other comprehensive income (loss), net of tax:		
Cash flow hedges		
Unrealized net gains arising during period, net of tax of $ – million and $ – million, respectively	—	0.1
Reclassification of net (gains) losses to net income, net of tax of $0.9 million and $0.6 million, respectively	(0.6)	0.9
Cash flow hedges, net	(0.6)	1.0
Defined benefit plans		
Pension and other postretirement benefit costs arising during period, net of tax of $(0.1) million and $ – million, respectively	(0.1)	—
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.3 million and $0.4 million, respectively	0.3	0.6
Defined benefit plans, net	0.2	0.6
Other comprehensive income (loss), net of tax	(0.4)	1.6
Comprehensive income	152.7	189.9
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	0.1	—
Comprehensive income attributed to common shareholders	$152.0	$189.1

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)	2014	2013
Assets		
Cash and cash equivalents	$56.6	$ 22.3
Collateral on deposit	74.4	37.4
Accounts receivable and accrued unbilled revenues, net of reserves of $61.9 and $49.4, respectively	1,543.8	1,037.0
Inventories	134.9	253.1
Assets from risk management activities	269.9	239.5
Regulatory assets	238.8	127.4
Assets held for sale	286.7	272.6
Deferred income taxes	—	31.4
Prepaid taxes	74.5	146.9
Other current assets	37.5	50.0
Current assets	2,717.1	2,217.6
Property, plant, and equipment, net of accumulated depreciation of $3,283.5 and $3,236.9, respectively	6,301.2	6,216.7
Regulatory assets	1,346.7	1,361.4
Assets from risk management activities	60.3	75.4
Equity method investments	548.1	540.9
Goodwill	662.1	662.1
Other long-term assets	166.7	169.4
Total assets	$11,802.2	$ 11,243.5
Liabilities and Equity		
Short-term debt	$321.9	$ 326.0
Current portion of long-term debt	100.0	100.0
Accounts payable	864.9	604.8
Liabilities from risk management activities	175.8	163.8
Accrued taxes	111.4	80.9
Regulatory liabilities	149.9	101.1
Temporary LIFO liquidation credit	150.9	—
Liabilities held for sale	36.7	49.1
Deferred income taxes	12.8	—
Other current liabilities	218.6	228.8
Current liabilities	2,142.9	1,654.5
Long-term debt	2,956.2	2,956.2
Deferred income taxes	1,439.9	1,390.3
Deferred investment tax credits	57.6	57.6
Regulatory liabilities	438.8	383.7
Environmental remediation liabilities	588.4	600.0
Pension and other postretirement benefit obligations	95.6	200.8
Liabilities from risk management activities	46.2	62.8
Asset retirement obligations	497.0	491.0
Other long-term liabilities	133.6	133.2

Long-term liabilities	6,253.3	6,275.6
Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,534,371 shares outstanding	80.0	79.9
Additional paid-in capital	2,653.4	2,660.5
Retained earnings	665.0	567.1
Accumulated other comprehensive loss	(23.6)	(23.2)
Shares in deferred compensation trust	(20.8)	(23.0)
Total common shareholders’ equity	3,354.0	3,261.3
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding	51.1	51.1
Noncontrolling interest in subsidiaries	0.9	1.0
Total liabilities and equity	$11,802.2	$ 11,243.5

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)	2014	2013
Operating Activities		
Net income	$153.1	$188.3
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	0.1	(6.1)
Depreciation and amortization expense	71.3	60.9
Recoveries and refunds of regulatory assets and liabilities	54.1	16.5
Net unrealized gains on energy contracts	(19.7)	(65.2)
Bad debt expense	19.3	9.3
Pension and other postretirement expense	7.2	15.9
Pension and other postretirement contributions	(68.6)	(63.2)
Deferred income taxes and investment tax credits	90.2	68.3
Equity income, net of dividends	(3.9)	(4.4)
Termination of tolling agreement with Fox Energy Company LLC	—	(50.0)
Other	1.1	6.3
Changes in working capital		
Collateral on deposit	(37.0)	15.4
Accounts receivable and accrued unbilled revenues	(531.5)	(182.8)
Inventories	121.6	137.9
Other current assets	(71.7)	45.4
Accounts payable	272.1	24.7
Temporary LIFO liquidation credit	150.9	83.2
Other current liabilities	54.7	19.2
Net cash provided by operating activities	263.3	319.6
Investing Activities		
Capital expenditures	(159.6)	(147.0)
Capital contributions to equity method investments	(5.1)	(1.7)
Acquisition of Fox Energy Company LLC	—	(391.6)
Grant received related to Crane Creek wind project	—	69.0
Other	1.4	(1.9)
Net cash used for investing activities	(163.3)	(473.2)
Financing Activities		
Short-term debt, net	(4.1)	74.0
Borrowing on term credit facility	—	200.0
Repayment of long-term debt	—	(22.0)
Proceeds from stock option exercises	0.4	6.4
Shares purchased for stock-based compensation	(9.8)	(2.0)
Payment of dividends		
Preferred stock of subsidiary	(0.8)	(0.8)
Common stock	(54.1)	(50.1)
Other	(3.7)	(8.3)
Net cash (used for) provided by financing activities	(72.1)	197.2

Change in cash and cash equivalents – continuing operations	27.9	43.6
Change in cash and cash equivalents – discontinued operations		
Net cash provided by (used for) operating activities	6.4	(0.6)
Net cash provided by investing activities	—	1.6
Net change in cash and cash equivalents	34.3	44.6
Cash and cash equivalents at beginning of period	22.3	27.4
Cash and cash equivalents at end of period	$56.6	$72.0
Cash paid for interest	$13.4	$4.8
Cash received for income taxes	$(62.7)	$(1.0)

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, 2014

Note 1—Financial Information

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, 2013. 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.

Reclassification

Assets and liabilities associated with the pending sale of UPPCO were reclassified as held for sale on our December 31, 2013, balance sheet to be consistent with the current period presentation. See Note 5, Dispositions, for more information on the pending sale of UPPCO.

Note 2—Cash and Cash Equivalents

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

Significant noncash transactions were:

	Three Months Ended March 31	
(Millions)	2014	2013
Construction costs funded through accounts payable	$92.3	$59.8
Equity issued for employee stock ownership plan	1.7	2.7
Equity issued for stock-based compensation plans	—	16.0
Equity issued for reinvested dividends	—	3.0

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Note 3—Risk Management Activities

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

(Millions)	Balance Sheet Presentation (1)	March 31, 2014 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$12.3	$0.3
Natural gas contracts	Long-term	1.0	0.1
Financial transmission rights (FTRs) (2)	Current	0.9	0.2
Petroleum product contracts	Current	0.1	—
Coal contracts	Current	—	1.1
Coal contracts	Long-term	1.8	0.4
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	56.0	41.7
Natural gas contracts	Long-term	20.9	10.9
Electric contracts	Current	200.8	132.5
Electric contracts	Long-term	36.6	34.8
	Current	270.1	175.8
	Long-term	60.3	46.2
Total		$330.4	$222.0

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

(2) Includes a $0.2 million risk management asset that was classified as held for sale at UPPCO. See Note 5, Dispositions, for more information.

(Millions)	Balance Sheet Presentation (1)	December 31, 2013 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$8.3	$1.0
Natural gas contracts	Long-term	1.8	0.1
FTRs (2)	Current	2.1	0.3
Petroleum product contracts	Current	0.1	—
Coal contracts	Current	—	1.9
Coal contracts	Long-term	0.2	0.8
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	57.6	42.9
Natural gas contracts	Long-term	29.5	18.6
Electric contracts	Current	172.0	117.7

Electric contracts	Long-term	43.9	43.3
	Current	240.1	163.8
	Long-term	75.4	62.8
Total		$315.5	$226.6

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

(2) Includes a $0.6 million risk management asset that was classified as held for sale at UPPCO. See Note 5, Dispositions, for more information.

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

	March 31, 2014		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$14.3	$0.6	$13.7
Nonregulated segments	314.0	193.0	121.0
Total	328.3	193.6	134.7
Derivative assets not subject to master netting or similar arrangements	2.1		2.1
Total risk management assets	$330.4		$136.8
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$0.6	$0.6	$—
Nonregulated segments	219.8	193.0	26.8
Total	220.4	193.6	26.8
Derivative liabilities not subject to master netting or similar arrangements	1.6		1.6
Total risk management liabilities	$222.0		$28.4

	December 31, 2013		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$12.3	$2.1	$10.2
Nonregulated segments	301.9	178.1	123.8
Total	314.2	180.2	134.0
Derivative assets not subject to master netting or similar arrangements	1.3		1.3
Total risk management assets	$315.5		$135.3
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$1.4	$1.4	$—
Nonregulated segments	222.1	178.1	44.0
Total	223.5	179.5	44.0
Derivative liabilities not subject to master netting or similar arrangements	3.1		3.1
Total risk management liabilities	$226.6		$47.1

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 received or 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, 2014	December 31, 2013
Cash collateral provided to others:		
Related to contracts under master netting or similar arrangements [1]	$74.6	$ 37.6
Other	1.1	1.1
Cash collateral received from others related to contracts under master netting or similar arrangements [2]	1.5	0.7

(1) Includes $1.3 million of cash collateral provided to others that was classified as held for sale at UPPCO at March 31, 2014 and December 31, 2013. See Note 5, Dispositions, for more information.

(2) Reflected in other current liabilities on the balance sheets.

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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 following table shows the aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a liability position:

(Millions)	March 31, 2014	December 31, 2013
Utility segments	$0.2	$ 0.6
Nonregulated segments	58.4	76.7

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, our collateral requirement would have been as follows:

(Millions)	March 31, 2014	December 31, 2013
Collateral that would have been required:		
Utility segments	$—	$ —
Nonregulated segments	199.7	197.6
Collateral already satisfied:		
Nonregulated segments — Letters of credit	20.0	4.5
Collateral remaining:		
Nonregulated segments	179.7	193.1

Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, coal purchase contracts, financial derivative contracts, and FTRs used to manage electric transmission congestion costs. The electric and natural gas 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 notional volumes of outstanding derivative contracts at the utilities and IBS were as follows:

	March 31, 2014			December 31, 2013		
(Millions, except barrels)	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	2,438.8	2.1	N/A	3,124.8	29.3	N/A
FTRs (kilowatt-hours)	N/A	N/A	1,448.7	N/A	N/A	3,633.1
Petroleum products (barrels)	113,000.0	20,000.0	N/A	102,811.0	14,000.0	N/A
Coal (tons)	4.3	—	N/A	4.8	—	N/A

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	2014	2013
Natural gas	Balance Sheet — Regulatory assets (current)	$0.9	$13.0
Natural gas	Balance Sheet — Regulatory assets (long-term)	(0.2)	0.8
Natural gas	Balance Sheet — Regulatory liabilities (current)	3.4	5.9
Natural gas	Balance Sheet — Regulatory liabilities (long-term)	(0.4)	0.8

Natural gas	Income Statement — Operating and maintenance expense	0.2	0.2
FTRs	Balance Sheet — Regulatory assets (current)	0.2	0.2
FTRs	Balance Sheet — Regulatory liabilities (current)	(0.2)	(0.4)
Coal	Balance Sheet — Regulatory assets (current)	0.2	1.9
Coal	Balance Sheet — Regulatory assets (long-term)	0.4	2.3
Coal	Balance Sheet — Regulatory liabilities (current)	—	(0.2)
Coal	Balance Sheet — Regulatory liabilities (long-term)	1.6	(2.2)

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Nonregulated Segments

Nonhedge Derivatives

IES enters into physical and financial derivative contracts that are used to manage commodity price risk primarily associated with retail electric and natural gas customer contracts.

IES had the following notional volumes of outstanding derivative contracts:

(Millions)	March 31, 2014 Purchases	March 31, 2014 Sales	December 31, 2013 Purchases	December 31, 2013 Sales
Commodity contracts				
Natural gas (therms)	919.2	774.3	1,199.9	1,065.4
Electric (kilowatt-hours)	40,473.7	25,245.0	49,186.3	30,813.8

Gains (losses) related to derivative contracts are recognized currently in earnings, as shown in the table below:

		Three Months Ended March 31	
(Millions)	Income Statement Presentation	2014	2013
Natural gas	Nonregulated revenue	$(36.9)	$3.4
Natural gas	Nonregulated cost of sales	33.0	(1.6)
Natural gas	Nonregulated revenue (reclassified from accumulated OCI) *	—	(0.1)
Electric	Nonregulated revenue	160.3	64.0
Electric	Nonregulated cost of sales	0.6	—
Electric	Nonregulated revenue (reclassified from accumulated OCI) *	—	(1.0)
Total		$157.0	$64.7

* Represents amounts reclassified from accumulated other comprehensive loss (OCI) related to cash flow hedges that were dedesignated in prior periods.

Note 4—Acquisitions

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

In September 2013, MERC entered into an agreement to purchase Alliant Energy Corporation's natural gas distribution business in southeast Minnesota. This transaction is subject to state and federal regulatory approvals. The purchase price will be based on book value as of the closing date, which is expected to approximate $11 million. We anticipate closing on this transaction later in 2014. It will not be material to us.

Acquisition of Fox Energy Center

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

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

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

(Millions)	
Assets acquired [1]	
Inventories	$3.0
Other current assets	0.4
Property, plant, and equipment	374.4
Other long-term assets [2]	15.6
Total assets acquired	$393.4
Liabilities assumed	
Accounts payable	$1.8
Total liabilities assumed	$1.8

(1) Relates to the electric utility segment.

(2) Intangible assets recorded for contractual services agreements. See Note 8, Goodwill and Other Intangible Assets, for more information.

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

WPS received regulatory approval to defer incremental costs incurred in 2013 associated with the purchase of the facility. These costs are included in WPS's 2015 proposed retail electric rate increase. See Note 20, Regulatory Environment, for more information. WPS's rate order effective January 1, 2014, included the costs of operating the Fox Energy Center.

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

Note 5—Dispositions

Dispositions at Electric Utility Segment

Pending Sale of UPPCO

In January 2014, we reached a definitive agreement to sell all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP (BBIP) for approximately $298.8 million. This price is subject to adjustments for various items, including working capital, pension contributions, and the reimbursement of any capital expenditures made by UPPCO in 2014 prior to the sale. BBIP approached us in early 2013 about purchasing UPPCO, and we came to an agreement in January 2014 that was approved by our Board of Directors. The transaction is subject to state and federal regulatory approvals and is expected to close later in 2014. Following the sale, IBS will provide certain administrative and operational services to UPPCO during a transition period of 18 to 30 months.

The pending sale of UPPCO does not meet the requirements under the accounting guidance to qualify as discontinued operations as WPS will have significant continuing cash flows related to certain power purchase transactions that will continue with UPPCO after the sale.

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

(Millions)	March 31, 2014	December 31, 2013
Current assets	$27.2	$26.5
Property, plant, and equipment, net of accumulated depreciation of $90.2 and $88.9, respectively	193.2	193.8
Other long-term assets	65.6	51.6
Total assets	$286.0	$271.9
Current liabilities	$12.0	$16.7
Long-term liabilities	24.7	32.4
Total liabilities	$36.7	$49.1

In addition to the amounts above, intercompany payables of $2.0 million and $1.6 million at March 31, 2014, and December 31, 2013, respectively, will be included in the sale. These balances were eliminated during consolidation and relate to certain power purchase transactions that will continue with WPS after the sale, as discussed above.

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Discontinued Operations at Holding Company and Other Segment

During the three months ended March 31, 2013, we recorded $6.0 million of after-tax gains in discontinued operations at the holding company and other segment. In 2013, we remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling a certain state income tax examination. We reduced the provision for income taxes related to this remeasurement.

Discontinued Operations at IES Segment

Potential Sale of Combined Locks Energy Center

IES is currently pursuing the sale of the Combined Locks Energy Center (Combined Locks), a natural gas-fired co-generation facility located in Wisconsin, as part of its long-term energy asset strategy.

Combined Locks had $0.7 million of assets that were classified as held for sale on the balance sheets at March 31, 2014, and December 31, 2013, which included inventories and property, plant, and equipment. During each of the three months ended March 31, 2014, and 2013, IES recorded after-tax losses of $0.1 million in discontinued operations related to Combined Locks.

Sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC

In March 2013, WPS Empire State, Inc., a subsidiary of IES, sold all of the membership interests of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse), both of which owned natural gas-fired generation plants located in the state of New York. During the three months ended March 31, 2013, IES recorded after-tax earnings of $0.2 million in discontinued operations related to Beaver Falls and Syracuse.

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, 2014. 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)	2014	2013
Balance at the beginning of period	$508.4	$476.6
Add: Earnings from equity method investment	22.5	21.7
Add: Capital contributions	5.1	1.7
Less: Dividends received	18.4	17.3
Balance at the end of period	$517.6	$482.7

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

	Three Months Ended March 31	
(Millions)	2014	2013
Income statement data		
Revenues	$163.3	$151.8
Operating expenses	78.6	69.8
Other expense	21.6	21.5
Net income	$63.1	$60.5

(Millions)	March 31, 2014	December 31, 2013
Balance sheet data		
Current assets	$79.2	$80.7
Noncurrent assets	3,563.9	3,509.5
Total assets	$3,643.1	$3,590.2
Current liabilities	$301.4	$381.5
Long-term debt	1,650.0	1,550.0
Other noncurrent liabilities	131.2	126.1
Shareholders' equity	1,560.5	1,532.6
Total liabilities and shareholders' equity	$3,643.1	$3,590.2

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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, 2014, we had a temporary LIFO liquidation credit of $150.9 million. 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, 2014, and 2013.

The identifiable intangible assets other than goodwill listed below are part of other current and long-term assets on the balance sheets. An insignificant amount was recorded as assets held for sale on the balance sheets.

	March 31, 2014			December 31, 2013		
(Millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Customer-related (1)	$26.8	$ (16.1)	$10.7	$26.8	$ (15.7)	$11.1
Contractual service agreements (2)	15.6	(2.4)	13.2	15.6	(1.8)	13.8
Renewable energy credits (3)	9.6	—	9.6	8.4	—	8.4
Compressed natural gas fueling contract assets (4)	5.6	(2.9)	2.7	5.6	(2.7)	2.9
Customer-owned equipment modifications (5)	4.0	(0.9)	3.1	4.0	(0.9)	3.1
Natural gas and electric contract assets (6)	3.9	(1.2)	2.7	3.9	(0.5)	3.4
Nonregulated easements (7)	3.7	(1.2)	2.5	3.7	(1.1)	2.6
Patents/intellectual property (8)	3.4	(0.6)	2.8	3.4	(0.5)	2.9
Other	0.5	(0.3)	0.2	0.5	(0.3)	0.2
Total	$73.1	$ (25.6)	$47.5	$71.9	$ (23.5)	$48.4
Unamortized intangible assets						
MGU trade name	$5.2	$ —	$5.2	$5.2	$ —	$5.2
Trillium trade name (9)	3.5	—	3.5	3.5	—	3.5
Pinnacle trade name (9)	1.5	—	1.5	1.5	—	1.5
Total intangible assets	$83.3	$ (25.6)	$57.7	$82.1	$ (23.5)	$58.6

(1) Represents customer relationship assets associated with PELLC's former nonregulated retail natural gas and electric operations, ITF's compressed natural gas fueling operations, and IES's retail natural gas operations. The remaining weighted-average amortization period for customer-related intangible assets at March 31, 2014, was approximately 11 years.

(2) Represents contractual service agreements related to maintenance on the combustion turbine generators at the Fox Energy Center. The remaining amortization period for these intangible assets at March 31, 2014, was approximately six years.

(3) Used at IES to comply with state Renewable Portfolio Standards and to support customer commitments.

(4) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at March 31, 2014, was approximately seven years.

(5) Relates to modifications made by IES 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, 2014, of approximately ten years.

(6) Represents the fair value of certain natural gas and electric customer contracts acquired by IES during 2013 that were not considered to be derivative instruments. The remaining amortization period for these intangible assets at March 31, 2014, was approximately four years.

(7) Relates to easements supporting a pipeline at IES. The easements are amortized on a straight-line basis, with a remaining amortization period at March 31, 2014, of approximately ten years.

(8) Represents the fair value of patents/intellectual property at ITF related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at March 31, 2014, was approximately eight years.

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

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income for the three months ended March 31, 2014, and 2013, was $1.0 million and $0.4 million, respectively.

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Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the three months ended March 31, 2014, and 2013, was $1.1 million and $0.5 million, respectively.

An insignificant amount of amortization expense was recorded in discontinued operations for the three months ended March 31, 2013.

The following table shows our estimated amortization expense for the next five years, including amounts recorded through March 31, 2014:

	For the Year Ending December 31				
(Millions)	2014	2015	2016	2017	2018
Amortization to be recorded in nonregulated cost of sales	$3.4	$2.0	$1.1	$0.9	$0.8
Amortization to be recorded in depreciation and amortization expense	4.3	4.2	4.0	3.9	3.8

Note 9—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	March 31, 2014		December 31, 2013	
Commercial paper	$321.9		$326.0	
Average interest rate on commercial paper	0.23	%	0.22	%

The commercial paper outstanding at March 31, 2014, had maturity dates ranging from April 1, 2014, through May 5, 2014.

Our average amount of commercial paper borrowings based on daily outstanding balances during the three months ended March 31, 2014, and 2013, was $247.1 million and $400.7 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 as of March 31:

(Millions)	Maturity	March 31, 2014	December 31, 2013
Revolving credit facility (Integrys Energy Group)	05/17/2014	$275.0	$275.0
Revolving credit facility (Integrys Energy Group)	05/17/2016	200.0	200.0
Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	635.0
Revolving credit facility (WPS)	05/17/2014	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		$1,610.0	$1,610.0
Less:			
Letters of credit issued inside credit facilities		$70.6	$52.4
Commercial paper outstanding		321.9	326.0
Available capacity under existing agreements		$1,217.5	$1,231.6

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			
	2014		2013	
Effective tax rate	37.0	%	37.6	%

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, 2014, and 2013.

During the three months ended March 31, 2014, 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 regulated natural gas utilities have obligations to distribute and sell natural gas to their customers, and the regulated electric utilities have obligations to distribute and sell electricity to their customers. The utilities expect to recover costs related to these obligations in future customer rates. Additionally, the majority of the energy supply contracts entered into by IES are to meet its contractual obligations to deliver energy to customers. The following table shows our minimum future commitments related to these purchase obligations as of March 31, 2014, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Year Contracts Extend Through	Total Amounts Committed	2014	2015	2016	2017	2018	Later Years
Natural gas utility supply and transportation	2028	$793.7	$128.2	$169.7	$158.5	$122.6	$71.7	$143.0
Electric utility								
Purchased power *	2029	918.0	59.8	49.4	42.8	53.2	54.0	658.8
Coal supply and transportation	2018	94.6	47.0	28.5	9.9	5.9	3.3	—
Nonregulated electricity and natural gas supply	2020	600.9	376.4	161.2	51.9	9.4	1.6	0.4
Total		$2,407.2	$611.4	$408.8	$263.1	$191.1	$130.6	$802.2

* Includes minimum future commitments for UPPCO related to power purchase contracts of $8.2 million for the years 2014 to 2024. In January 2014, we announced an agreement to sell UPPCO. See Note 5, Dispositions, for more information.

We and our subsidiaries also had commitments of $1,163.3 million in the form of purchase orders issued to various vendors at March 31, 2014, that relate to normal business operations, including construction projects. Included in this amount are purchase orders issued to various vendors of UPPCO for $12.2 million.

(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 alleging 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™, on Weston 3,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,
- beneficial environmental projects totaling $6.0 million (various options, including capital projects, are available), 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. The early retirement of certain Weston and Pulliam units mentioned in the Consent Decree has been announced.

WPS received approval from the PSCW in its 2014 rate order to recover prudently incurred 2014 costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty. We also believe that prudently incurred costs after 2014 will be recoverable from customers based on past precedent with the PSCW.

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, 2014. It is unknown whether the Sierra Club will take further action in the future.

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Columbia and Edgewater CAA Issues:
In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric and WPS. The NOV alleges 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 (Joint Owners) reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million (various options, including capital projects, are available), and
- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain of the Columbia and Edgewater units. As of March 31, 2014, no decision had been made on how to address this requirement. Therefore, retirement of the Columbia and Edgewater units mentioned in the Consent Decree was not considered probable.

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.

Weston Title V Air Permit:
In July 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 filed Petitions for Judicial Review and requests for contested case proceedings regarding various aspects of the permit. The WDNR granted all parties' requests for contested case proceedings. WPS has filed permit amendment applications such that, if the facility permits and the Title V air permit are amended in accordance with the applications, several of the issues WPS raised would be resolved. The contested case petitions have not yet been referred to an Administrative Law Judge. The Petitions for Judicial Review, by all parties, have been stayed pending the resolution of the contested cases.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule requires a 40% reduction from historical baseline mercury emissions, beginning January 1, 2010, through the end of 2014. Beginning in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the historical baseline. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts, but less than 150 megawatts, must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of March 31, 2014, WPS estimated capital costs of approximately $8 million for its wholly owned plants to achieve the required reductions. The capital costs are expected to be recovered in future rates.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. The State of Wisconsin is in the process of revising 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.

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 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, and on April 29, 2014, the Supreme Court upheld the CSAPR rule and remanded the case to the Court of Appeals for the D.C. Circuit. There are remaining issues before the D.C. Circuit, and there will need to be additional rulemakings before CSAPR is implemented. As a result, it is premature to speculate on what additional controls or other actions, if any, we may be required to implement. WPS expects to recover any future compliance costs in future rates. The potential impact on IES is not expected to be material.

The stay of CSAPR is still in effect. 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), and the EPA has not revised it to reflect the reinstatement of CAIR. Although particulate emissions also contribute to visibility impairment, the WDNR's modeling has shown the impairment to be so insignificant that additional capital expenditures on controls may not be warranted.

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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 sheets include liabilities of $588.2 million that we have estimated and accrued for as of March 31, 2014, 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, 2014, cash expenditures for environmental remediation not yet recovered in rates were $34.1 million. Our balance sheets also include a regulatory asset of $622.3 million at March 31, 2014, 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	Expiration		
(Millions)	at March 31, 2014	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1] [5]	$684.5	$412.6	$31.7	$240.2
Standby letters of credit [2] [5]	74.1	70.7	3.3	0.1
Surety bonds [3]	29.1	29.1	—	—
Other guarantees [4] [5]	55.3	1.5	—	53.8
Total guarantees	$843.0	$513.9	$35.0	$294.1

(1) Consists of (a) $497.7 million, $5.0 million, and $2.0 million to support the business operations of IES, IBS, and UPPCO, respectively, and (b) $126.7 million, $52.9 million, and $0.2 million related to natural gas supply at MERC, MGU and ITF, 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 $72.1 million issued to support IES’s operations and $2.0 million issued to support ITF, MERC, MGU, NSG, PGL, UPPCO, and WPS.

These amounts are 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) Consists of (a) $35.0 million to support IES's future payment obligations related to its distributed solar generation projects. This guarantee is not reflected on our balance sheets; (b) $10.0 million related to the sale agreement for IES's Texas retail marketing business, which included a number of customary representations, warranties, and indemnification provisions. 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) $1.8 million related to the sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC. IES's guaranteed the buyer's performance under certain derivative contracts that the buyer assumed from WPS Empire State, Inc. in conjunction with the sale; (d) $2.4 million related to the performance of an operating and maintenance agreement by ITF; and (e) $6.1 million related to other indemnifications primarily for workers compensation coverage. The amounts discussed in items (c) through (e) above are not reflected on our balance sheets.

(5) Consists of $3.4 million of guarantees related to UPPCO. See Note 5, Dispositions, for more information on the pending sale of UPPCO.

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Note 13—Employee 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)	2014	2013	2014	2013
Service cost	$6.6	$7.5	$5.9	$6.5
Interest cost	19.7	17.8	7.1	6.3
Expected return on plan assets	(28.9)	(26.6)	(8.8)	(7.7)
Amortization of prior service cost (credit)	0.2	1.0	(1.3)	(0.6)
Amortization of net actuarial loss	8.4	13.5	0.7	2.0
Net periodic benefit cost	$6.0	$13.2	$3.6	$6.5

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.

On March 1, 2014, we remeasured the obligations of certain other postretirement benefit plans. The remeasurement was necessary because we will replace the current retiree medical plans for participants age 65 and older with a Medicare Advantage plan starting in 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, 2014, we contributed $68.6 million to our pension plans. Amounts contributed to our other postretirement benefit plans were not significant. We expect to contribute an additional $3.7 million to our pension plans and $11.8 million to our other postretirement benefit plans during the remainder of 2014, dependent upon various factors affecting us, including our liquidity position and tax law changes.

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:

(Millions)	2014	2013
Stock options	$0.3	$0.4
Performance stock rights	0.5	2.2
Restricted share units	3.1	2.8
Nonemployee director deferred stock units	0.2	0.3
Total stock-based compensation expense	$4.1	$5.7
Deferred income tax benefit	$1.6	$2.3

No stock-based compensation cost was capitalized during the three months ended March 31, 2014, and 2013.

Stock Options

The fair value of stock option awards granted is estimated using a binomial lattice model. The expected term of option awards is derived from the output of the binomial lattice model and represents the period of time that options are expected to be outstanding. 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 the 10-year historical volatility of our stock price. The following table shows the assumptions incorporated into the valuation model:

	February 2014 Grant
Expected term	8 years
Risk-free interest rate	0.12% – 2.88%
Expected dividend yield	5.28%
Expected volatility	18%

The weighted-average fair value per stock option granted during the three months ended March 31, 2014, and 2013, was $6.70 and $6.03, respectively.

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A summary of stock option activity for the three months ended March 31, 2014, and information related to outstanding and exercisable stock options at March 31, 2014, 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, 2013	1,550,374	$ 50.93		
Granted	264,332	55.23		
Exercised	(11,504)	45.45		
Outstanding at March 31, 2014	1,803,202	$ 51.60	6.6	$14.5
Exercisable at March 31, 2014	1,114,027	$ 49.75	5.1	$11.0

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, 2014. This is calculated as the difference between our closing stock price on March 31, 2014, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised was not significant during the three months ended March 31, 2014, and was $1.9 million during the three months ended March 31, 2013. The actual tax benefit realized for the tax deductions from these option exercises was not significant during the three months ended March 31, 2014, and 2013.

As of March 31, 2014, $2.5 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.0 years.

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:

	2014
Risk-free interest rate	0.34% – 0.57%
Expected dividend yield	5.28% – 5.33%
Expected volatility	15% – 22%

A summary of the activity for the three months ended March 31, 2014, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value *
Outstanding at December 31, 2013	85,749	$ 46.62
Granted	21,146	44.28
Adjustment for shares not distributed	(45,748)	43.29
Outstanding at March 31, 2014	61,147	$ 48.31

* 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, and 2013, was $44.28 and $48.50, per performance stock right, respectively.

A summary of the activity for the three months ended March 31, 2014, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2013	198,904
Granted	84,529
Adjustment for shares not distributed	(39,001)
Outstanding at March 31, 2014	244,432

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of March 31, 2014, was $38.73 per performance stock right.

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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. The total intrinsic value of shares distributed during the three months ended March 31, 2013, was $8.8 million. The actual tax benefit realized for the tax deductions from the distribution of shares during the three months ended March 31, 2013, was $3.6 million.

As of March 31, 2014, $5.2 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 1.6 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, 2014, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2013	511,301	$ 52.24
Granted	214,953	55.23
Dividend equivalents	6,169	54.45
Vested and released	(204,322)	49.73
Forfeited	(781)	54.42
Outstanding at March 31, 2014	527,320	$ 54.45

The weighted-average grant date fair value of restricted share units awarded during the three months ended March 31, 2014, and 2013, was $55.23 and $56.00 per unit, respectively.

The total intrinsic value of restricted share unit awards vested and released during the three months ended March 31, 2014, and 2013, was $11.1 million and $11.4 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, 2014, and 2013, was $4.4 million and $4.6 million respectively.

As of March 31, 2014, $18.7 million of compensation cost related to unvested and outstanding restricted share units was expected to be recognized over a weighted-average period of 2.5 years.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. These awards generally vest over one year; therefore, the expense is recognized pro-rata over the year in which the grant occurs. The number of DSUs granted is calculated by dividing a set dollar amount by our closing common stock price on December 31 of the prior year. Nonemployee directors also receive forfeitable dividend equivalents in the form of additional DSU's.

Note 15—Common Equity

We had the following changes to issued common stock during the three months ended March 31, 2014:

Balance at December 31, 2013	79,919,176
Shares issued	
Employee Stock Ownership Plan	31,764
Stock Investment Plan	12,151
Balance at March 31, 2014	79,963,091

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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
01/01/2013 – 02/04/2013	Purchased shares on the open market

The following table reconciles common shares issued and outstanding:

	March 31, 2014		December 31, 2013	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,963,091		79,919,176	
Less:				
Deferred compensation rabbi trust	428,720	$48.60	473,796	$48.50
Total common shares outstanding	79,534,371		79,445,380	

* 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.

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, and certain shares issuable under the deferred compensation plan. As the obligation for the 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)	2014	2013
Numerator:		
Net income from continuing operations	$153.2	$182.2
Discontinued operations, net of tax	(0.1)	6.1
Preferred stock dividends of subsidiary	(0.8)	(0.8)
Noncontrolling interest in subsidiaries	0.1	—
Net income attributed to common shareholders	$152.4	$187.5
Denominator:		
Average shares of common stock — basic	80.2	78.7
Effect of dilutive securities		
Stock-based compensation	0.3	0.4
Deferred compensation	—	0.2
Average shares of common stock — diluted	80.5	79.3
Earnings per common share		

Basic	$1.90	$2.38
Diluted	1.89	2.37

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)	2014	2013
Stock-based compensation	0.7	0.2
Deferred compensation	0.3	—

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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 regulated 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.

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, 2014, these covenants restricted the payment of any dividends beyond the amount allowed under our subsidiary requirements described above.

As of March 31, 2014, total restricted net assets were $1,846.5 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $146.8 million at March 31, 2014.

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

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

Capital Transactions with Subsidiaries

During the three months ended March 31, 2014, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
IBS	$ —	$ —	$ 15.0
ITF [(1)]	—	—	17.4
MERC	—	18.0	—
MGU	—	7.0	—

UPPCO	—	3.5	—
WPS	28.0	—	—
WPS Investments, LLC [2]	18.3	—	5.1
Total	$ 46.3	$ 28.5	$ 37.5

(1) ITF is a direct wholly owned subsidiary of PELLC. As a result, it makes distributions to PELLC, and receives 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, WPS, and UPPCO. At March 31, 2014, we had an 86.37% ownership interest, while WPS and UPPCO had an 11.24% and 2.39% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2014, all equity contributions to WPS Investments, LLC were made solely by us.

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Note 16—Accumulated Other Comprehensive Loss

The following tables show the changes, net of tax, to our accumulated other comprehensive loss during the three months ended March 31:

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 income (loss)	(0.6)	0.2	(0.4)
Ending balance at March 31, 2014	$ (3.7)	$ (19.9)	$ (23.6)

Three Months Ended March 31, 2013 (Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Beginning balance at December 31, 2012	$ (5.2)	$ (35.7)	$ (40.9)
Other comprehensive income before reclassifications	0.1	—	0.1
Amounts reclassified out of accumulated other comprehensive loss	0.9	0.6	1.5
Net current period other comprehensive income	1.0	0.6	1.6
Ending balance at March 31, 2013	$ (4.2)	$ (35.1)	$ (39.3)

The following table shows the reclassifications out of accumulated other comprehensive loss during the three months ended March 31:

(Millions)	Amount Reclassified Three Months Ended March 31 2014	2013	Affected Line Item in the Statements of Income
Losses on cash flow hedges			
Utility commodity derivative contracts	$—	$0.2	Operating and maintenance expense (1) (2)
Nonregulated commodity derivative contracts	—	1.1	Nonregulated revenues (2)
Interest rate hedges	0.3	0.2	Interest expense
	0.3	1.5	Total before tax
	0.9	0.6	Tax expense
	(0.6)	0.9	Net of tax
Defined benefit plans			
Amortization of prior service credits	(0.1)	(0.1)	(3)
Amortization of net actuarial losses	0.7	1.1	(3)
	0.6	1.0	Total before tax
	0.3	0.4	Tax expense
	0.3	0.6	Net of tax
Total reclassifications	$(0.3)	$1.5	

(1) This item relates to changes in the price of natural gas used to support utility operations.

(2) We no longer designate commodity contracts as cash flow hedges.

(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

Consolidated Variable Interest Entities

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. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture is loans from ITF. We determined that the joint venture is a variable interest entity and that ITF was the primary beneficiary, which required us to consolidate the assets, liabilities, and statements of income of the joint venture. At March 31, 2014, and December 31, 2013, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of AMP Trillium LLC assets and liabilities included on our balance sheets were also not significant.

In April 2014, ITF and AMP Americas LLC restructured this joint venture. As a result of the restructuring, our influence over the activities that most significantly impact the variable interest entity's economic performance decreased. We have determined that ITF is no longer the primary beneficiary of this variable interest entity and that we are no longer required to consolidate the joint venture. Therefore, we started accounting for this variable interest entity as an equity method investment in April 2014.

Unconsolidated Variable Interest Entities

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 compressed natural gas fueling stations. We 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 its activities. We instead account for this variable interest entity as an equity method investment. At March 31, 2014, and December 31, 2013, the assets and liabilities on our balance sheets related to our involvement with this variable interest entity consisted of insignificant receivables. Our maximum exposure to loss as a result of involvement with this variable interest entity was also not significant.
We have a variable interest in an entity through a power purchase agreement at UPPCO that reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under this agreement. This contract for 17.5 megawatts of capacity expires in December 2014. For a variety of reasons, including qualitative factors such as the length of the remaining term of the contract compared with the remaining life of the plant and the fact that we do not have the power to direct the operations and maintenance of the facility, we determined we are not the primary beneficiary of this variable interest entity and that consolidation is not required. At March 31, 2014, and December 31, 2013, the assets and liabilities on our balance sheets that related to our involvement with this variable interest entity pertained to working capital accounts and represented the amounts we owed for current deliveries of power. We have not guaranteed any debt or provided any equity support, liquidity arrangements, performance guarantees, or other commitments associated with the contract. Our maximum exposure to loss as a result of involvement with this variable interest entity was not significant.

Note 18—Fair Value

Fair Value Measurements

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. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model.

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.

We primarily determine fair value using a market-based approach that uses observable market inputs where available, and internally developed inputs only when observable market data is not readily available. For the unobservable inputs, consideration is given to the assumptions that market participants would use in valuing the asset or liability. These factors include not only the credit standing of the counterparties involved, but also the impact of our nonperformance risk on our liabilities.

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 include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), and price correlation (for cross commodity contracts). These inputs are available through multiple sources, including exchanges and brokers. Transactions valued using these inputs are classified in Level 2.

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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:

- While forward price curves may have been based on observable information, significant assumptions may have been made regarding monthly shaping and locational basis differentials.
- Certain transactions were valued using price curves that extended beyond an observable period. Assumptions were made to extrapolate prices from the last observable period through the end of the transaction term, primarily through the use of historically settled data or correlations to other 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 trading functions within the organization. To validate the reasonableness of our fair value inputs, our risk management department compares changes in valuation and researches any significant differences in order to determine the underlying cause. Changes to the fair value inputs are made if necessary.

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

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

	March 31, 2014			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$0.9	$12.4	$—	$13.3
Financial transmission rights (FTRs)	—	—	0.9	0.9
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	1.8	1.8
Nonregulated Segments				
Natural gas contracts	20.6	28.8	27.5	76.9
Electric contracts	88.0	127.6	21.8	237.4
Total Risk Management Assets	$109.6	$168.8	$52.0	$330.4
Investment in exchange-traded funds	$16.2	$—	$—	$16.2
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.2	$0.2	$—	$0.4
FTRs	—	—	0.2	0.2
Coal contracts	—	—	1.5	1.5
Nonregulated Segments				
Natural gas contracts	10.2	20.4	22.0	52.6
Electric contracts	112.3	51.9	3.1	167.3
Total Risk Management Liabilities	$122.7	$72.5	$26.8	$222.0
	$—	$—	$7.8	$7.8

Contingent consideration related to the acquisition of Compass Energy Services (Compass)

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	December 31, 2013			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$2.4	$7.7	$—	$10.1
FTRs	—	—	2.1	2.1
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	0.2	0.2
Nonregulated Segments				
Natural gas contracts	16.3	35.2	35.6	87.1
Electric contracts	65.1	134.9	15.9	215.9
Total Risk Management Assets	$83.9	$177.8	$53.8	$315.5
Investment in exchange-traded funds	$15.9	$—	$—	$15.9
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.5	$0.6	$—	$1.1
FTRs	—	—	0.3	0.3
Coal contracts	—	—	2.7	2.7
Nonregulated Segments				
Natural gas contracts	14.3	22.0	25.2	61.5
Electric contracts	98.8	58.7	3.5	161.0
Total Risk Management Liabilities	$113.6	$81.3	$31.7	$226.6
Contingent consideration related to the acquisition of Compass	$—	$—	$7.8	$7.8

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 3, Risk Management Activities, for more information.

The following tables show net risk management assets transferred between the levels of the fair value hierarchy:

	Nonregulated Segments — Natural Gas Contracts					
	Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	0.1	$—	N/A	—
Transfers into Level 3 from	—	0.9	N/A	—	0.2	N/A

	Nonregulated Segments — Electric Contracts					
	Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	4.4	$—	N/A	5.5
Transfers into Level 3 from	—	2.6	N/A	—	—	N/A

Derivatives are transferred between the levels of the fair value hierarchy primarily due to changes in the source of data used to construct price curves as a result of changes in market liquidity. We recognize transfers between the levels at the value as of the end of the reporting period.

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The amounts and percentages 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, 2014:

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	$ 0.9	$ 0.2	Market-based	Forward market prices ($/megawatt-month) (1)	$172.92
Coal contracts	1.8	1.5	Market-based	Forward market prices ($/ton) (2)	$12.11 — $15.25
Nonregulated Segments					
Natural gas contracts	27.5	22.0	Market-based	Forward market prices ($/dekatherm) (3)	($2.59) — $3.85
				Probability of default (4)	11.6% — 51.0%
Electric contracts	21.8	3.1	Market-based	Forward market prices ($/megawatt-hours) (3)	($5.02) — $10.06
				Probability of default (4)	26.0%
				Option volatilities (5)	19.8% — 155.6%
				Monthly curve shaping (6)	(27.0)%
Contingent consideration related to the acquisition of Compass	N/A	7.8	Income-based	Growth rate (7)	(13.2)% - 49.3%

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

(2) Represents third-party forward market pricing.

(3) Represents unobservable basis spreads developed using historical settled prices that are applied to observable market prices at various natural gas and electric locations, as well as unobservable adjustments made to extend observable market prices beyond the quoted period through the end of the transaction term.

(4) Based on Moody's one-year counterparty default percentages.

(5) Represents the range of volatilities used in the valuation of options. Volatilities are derived from an internal model using volatility curves from third parties.

(6) Represents adjustments made to forward market price curves to disaggregate average prices of multiple periods into discrete monthly prices.

(7) Represents the range of assumed growth rates of earnings before interest, taxes, and amortization input into the valuation model.

Significant changes in historical settlement prices, forward commodity prices, and option volatilities would result in a directionally similar significant change in fair value. Significant changes in probability of default would result in a significant directionally opposite change in fair value. Changes in the adjustments to prices related to monthly curve shaping would affect fair value differently depending on their direction. A significant decrease in the growth rate used to value the contingent consideration would result in a directionally similar significant change in fair value. A significant increase in the growth rate would not have a significant impact on the fair value as the contingent consideration is limited to $8.0 million.

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, 2014	Nonregulated Segments			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$10.4	$12.4	$ (7.8)	$1.8	$ (2.5)	$14.3
Net realized and unrealized (losses) gains included in earnings	(6.2)	12.6	—	0.4	—	6.8
Net unrealized gains recorded as regulatory assets or liabilities	—	—	—	—	2.2	2.2
Purchases	—	0.7	—	(0.1)	—	0.6
Sales	—	(0.7)	—	—	—	(0.7)
Settlements	0.5	(4.5)	—	(1.4)	0.6	(4.8)
Net transfers into Level 3	0.9	2.6	—	—	—	3.5
Net transfers out of Level 3	(0.1)	(4.4)	—	—	—	(4.5)
Balance at the end of the period	$5.5	$18.7	$ (7.8)	$0.7	$ 0.3	$17.4
Net unrealized (losses) gains included in earnings related to instruments still held at the end of the period	$(6.2)	$12.6	$ —	$—	$ —	$6.4

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Three Months Ended March 31, 2013	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$ 3.9	$ (4.3)	$ 2.0	$ (6.5)	$ (4.9)
Net realized and unrealized (losses) gains included in earnings	(1.5)	15.1	0.3	—	13.9
Net unrealized (losses) gains recorded as regulatory assets or liabilities	—	—	(0.2)	3.1	2.9
Purchases	—	0.7	—	—	0.7
Settlements	(0.9)	0.1	(1.2)	(1.2)	(3.2)
Net transfers into Level 3	0.2	—	—	—	0.2
Net transfers out of Level 3	—	(5.5)	—	—	(5.5)
Balance at the end of the period	$ 1.7	$ 6.1	$ 0.9	$ (4.6)	$ 4.1
Net unrealized (losses) gains included in earnings related to instruments still held at the end of the period	$ (1.5)	$ 15.1	$ —	$ —	$ 13.6

Realized and unrealized gains and losses included in earnings related to IES's risk management assets and liabilities are recorded through nonregulated revenue or nonregulated cost of sales on the statements of income, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities 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 utility cost of fuel, natural gas, and purchased power 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, 2014		December 31, 2013	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$ 3,056.2	$ 3,076.4	$ 3,056.2	$ 3,031.6
Preferred stock of subsidiary	51.1	57.3	51.1	61.2

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 19—Advertising Costs

Costs associated with certain natural gas and electric direct-response advertising campaigns at IES were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. Capitalized direct-response advertising costs, net of accumulated amortization, totaled $4.5 million and $5.2 million as of March 31, 2014, and December 31, 2013, respectively. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment. We did not record any significant impairments during the three months ended March 31, 2014, and 2013.

Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years. The amortization of direct-response advertising costs was $1.3 million and $3.0 million for the three months ended March 31, 2014, and 2013, respectively.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. Other advertising expense was $1.7 million and $2.3 million for the three months ended March 31, 2014, and 2013, respectively.

Note 20—Regulatory Environment

Wisconsin

2015 Rate Case

In April 2014, WPS filed an application with the PSCW to increase retail electric rates $76.8 million and to decrease natural gas rates $1.6 million, with rates expected to be effective January 1, 2015. WPS's request reflects a 10.60% return on common equity and a target common equity ratio of 50.50% in WPS's regulatory capital structure. The proposed retail electric rate increase is primarily driven by the completion of a fuel refund to customers in 2014 rates, which kept rates flat in 2014, as well as a reduction in refunds associated with decoupling. In 2015, fuel and purchased power costs are expected to increase, as are transmission costs and general inflation. The proposed retail electric rate increase also includes WPS's request to recover deferred costs over four years related to the 2013 acquisition of the Fox Energy Center. Finally, capital costs associated with both previously approved environmental upgrades at the Columbia plant as well as our efforts to improve electric reliability by converting company distribution lines with lower performance history from overhead to underground are also contributing to the increase in retail electric rates. The proposed retail natural gas rate decrease is driven by 2013 decoupling over-collections, which will be refunded to customers in 2015. An increase in non-fuel operating and maintenance costs, including the impact of general inflation, and an increase in return on equity partially offset the effect of the 2013 decoupling over-collections.

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 discussed below, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were 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 to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 related to the Pulliam and Weston sites. See Note 11, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its existing decoupling mechanism, beginning January 1, 2014.

2013 Rates

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

Section 1603 Grants for the Crane Creek wind project.

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

Michigan

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 reflect 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 existing 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 existing uncollectible expense true-up mechanism after December 31, 2013.

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MGU Depreciation Case

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

2014 UPPCO Rates

In December 2013, the MPSC issued a final written order for UPPCO, effective January 1, 2014. The order authorized a retail electric rate increase of $5.8 million. The rates reflected a 10.15% return on common equity and a common equity ratio of 56.74% in UPPCO's regulatory capital structure. The order required UPPCO to terminate its existing decoupling mechanism after December 31, 2013. In addition, the order required UPPCO to achieve certain minimum line clearance performance metrics for recovery of costs related to clearing trees and other natural obstructions away from power lines. If these metrics are not achieved, or if the minimum spending level is not reached, UPPCO may be required to refund certain amounts to customers.

Illinois

2015 Rate Cases

In February 2014, PGL and NSG filed applications with the ICC to increase retail natural gas rates $128.9 million and $7.1 million, respectively, with rates expected to be effective in early 2015. Both PGL's and NSG's requests reflect a 10.25% return on common equity. The requests reflect target common equity ratios of 50.41% for NSG and 50.31% for PGL in their respective regulatory capital structures. The proposed retail natural gas rate increases are primarily driven by increased capital investments, in particular for main replacement, a loss in revenues as a result of lower projected sales volumes, increased costs of debt and common equity, and increased operating expenses. The increase in operating expenses relates to pipeline safety and other compliance work, a general wage increase, higher depreciation costs, and higher invested capital taxes. PGL's application also removes from the proposed 2015 rates the investment and related expenses that PGL plans to recover through its new Qualifying Infrastructure Plant rider, as discussed below. PGL and NSG proposed no changes to the continued use of their decoupling mechanisms and uncollectible expense true-up mechanisms.

Qualifying Infrastructure Plant (QIP) 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 Illinois natural gas infrastructure upgrades that will be 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, and the ICC approved the tariff in January 2014. The rider became effective on January 1, 2014.

2013 Rates

In June 2013, the ICC issued a final written order for PGL and NSG, effective June 27, 2013. The order authorized a retail natural gas rate increase of $57.2 million for PGL and $6.6 million for NSG. The rates for PGL reflected a 9.28% return on common equity and a common equity ratio of 50.43% in PGL's regulatory capital structure. The rates for NSG reflected a 9.28% return on common equity and a common equity ratio of 50.32% in NSG's regulatory capital structure. The rate order also allowed PGL and NSG to continue the use of their decoupling mechanisms, as affirmed by the Illinois Appellate Court (Court).

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 Court.

2012 Decoupling

The ICC issued a final written order, effective January 21, 2012, which approved permanent decoupling mechanisms for PGL and NSG. The Illinois Attorney General and Citizens Utility Board appealed to the Court the ICC's authority to approve PGL's and NSG's decoupling mechanisms and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General's motion to make revenues collected under the permanent decoupling mechanism subject to refund and directing PGL and NSG to track amounts that would be due to customers or the companies from the permanent decoupling mechanisms. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 were uncertain, and PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Court issued an opinion that affirmed the ICC's order approving the permanent decoupling mechanism. As a result, the reserves recorded in 2012 were reversed in the first quarter of 2013. PGL's and NSG's permanent decoupling mechanism was in place for 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Court's decision. The Illinois Supreme Court granted the request in September 2013, and briefing is in progress. The Illinois Supreme Court has no deadline by which it must act. Decoupling amounts recorded in 2012 were fully recovered and amounts in 2013 are being refunded to customers in 2014. Decoupling amounts in 2014 will continue to be accrued, absent an adverse Illinois Supreme Court decision.

Minnesota

2014 Rate Case

In September 2013, MERC filed an application with the MPUC to increase retail natural gas distribution rates by \$14.2 million. MERC's request reflected a 10.75% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure. The request was primarily driven by general inflation, property taxes, improvements to customer service programs, efforts to expand the customer base which would have a positive rate effect in the future, and operating and maintenance projects to ensure reliability and safety for customers.

In December 2013, the MPUC approved an interim rate order authorizing a retail natural gas rate increase for MERC of \$10.5 million, effective January 1, 2014. The interim rates reflect a 9.70% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure. The interim rate increase is subject to refund pending the final rate order, which is expected in the fourth quarter of 2014.

In April 2014, MERC filed rebuttal testimony in response to recommendations of the Department of Commerce and the Attorney General to increase retail natural gas rates by \$2.9 million to \$6.0 million. MERC's rebuttal testimony reflected a revised increase in retail natural gas rates of \$12.2 million. The revised request is lower than the initial application and is primarily driven by increased sales volume forecasts and revised natural gas costs based on more recent data available. Lower pension and benefit cost estimates also contributed to the revised request. The revised request reflects a 10.75% return on common equity and a common equity ratio of 50.31% in MERC's regulatory capital structure, which did not change from the initial application.

2011 Rates Finalized in 2013

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

Note 21—Segments of Business

At March 31, 2014, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the regulated electric utility operations of UPPCO and WPS.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- IES is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, IES invests in energy assets with renewable attributes, primarily distributed solar assets.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company, ITF, 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, 2014								
External revenues	$1,267.5	$349.2	$ —	$ 1,616.7	$1,289.6	$18.6	$ —	$ 2,924.9
Intersegment revenues	4.5	—	—	4.5	2.6	0.4	(7.5)	—
Depreciation and amortization expense	36.4	25.6	—	62.0	2.9	6.5	(0.1)	71.3
Earnings from equity method investments	—	—	22.5	22.5	0.1	0.3	—	22.9
Miscellaneous income	0.3	3.5	—	3.8	0.3	5.4	(3.5)	6.0
Interest expense	13.4	11.7	—	25.1	0.5	17.0	(3.5)	39.1
Provision (benefit) for income taxes	66.7	18.1	8.8	93.6	5.9	(9.7)	—	89.8
Net income (loss) from continuing operations	99.2	31.8	13.7	144.7	10.9	(2.4)	—	153.2
Discontinued operations	—	—	—	—	(0.1)	—	—	(0.1)
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	10.8	(2.3)	—	152.4

	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, 2013								
External revenues	$792.0	$331.8	$ —	$ 1,123.8	$545.4	$9.0	$ —	$ 1,678.2
Intersegment revenues	1.9	—	—	1.9	0.3	0.4	(2.6)	—
Depreciation and amortization expense	32.2	21.5	—	53.7	2.7	4.6	(0.1)	60.9
Earnings from equity method investments	—	—	21.7	21.7	0.2	0.4	—	22.3
Miscellaneous income	0.2	1.6	—	1.8	0.4	7.2	(3.7)	5.7
Interest expense	12.7	9.1	—	21.8	0.5	10.7	(3.7)	29.3
	63.3	16.1	8.3	87.7	27.3	(5.4)	—	109.6

Provision (benefit) for income taxes								
Net income (loss) from continuing operations	89.8	29.3	13.4	132.5	51.3	(1.6)	—	182.2
Discontinued operations	—	—	—	—	0.1	6.0	—	6.1
Preferred stock dividends of subsidiary	(0.1)	(0.7)	—	(0.8)	—	—	—	(0.8)
Net income attributed to common shareholders	89.7	28.6	13.4	131.7	51.4	4.4	—	187.5

Note 22—New Accounting Pronouncements

Recently Issued Accounting Guidance Not Yet Effective

Accounting Standards Update (ASU) 2014-08, "Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity," was issued in April 2014. The guidance raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. The guidance is effective for us for the reporting period ending March 31, 2015. The guidance applies prospectively to new disposals and new classifications of disposal groups as held for sale after the effective date.

ASU 2014-01, "Accounting for Investments in Qualified Affordable Housing Projects," was issued in January 2014. The guidance allows investors to use the proportional amortization method to account for investments in qualified affordable housing projects if certain conditions are met. Under that method, which replaces the effective yield method, an investor amortizes the cost of its investment, in proportion to the tax credits and other tax benefits it receives, to income tax expense. The guidance also requires new disclosures for all investments in these types of projects. The

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guidance is effective for us for the reporting period ending March 31, 2015. Although we have investments in affordable housing projects, adoption of this guidance is not expected to have a significant impact 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, 2013.

SUMMARY

We are a diversified energy holding company with regulated 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 2014	2013	Change in 2014 Over 2013
Natural gas utility operations	$99.1	$89.7	10.5 %
Electric utility operations	31.1	28.6	8.7 %
Electric transmission investment	13.7	13.4	2.2 %
IES's operations	10.8	51.4	(79.0)%
Holding company and other operations	(2.3)	4.4	N/A
Net income attributed to common shareholders	$152.4	$187.5	(18.7)%
Basic earnings per share	$1.90	$2.38	(20.2)%
Diluted earnings per share	$1.89	$2.37	(20.3)%
Average shares of common stock			
Basic	80.2	78.7	1.9 %
Diluted	80.5	79.3	1.5 %

First Quarter 2014 Compared with First Quarter 2013

The $35.1 million decrease in our earnings was driven by:

- A $28.6 million after-tax non-cash decrease in margins at IES related to derivative and inventory fair value adjustments.
- A $23.3 million after-tax increase in operating expenses at the utilities, excluding items directly offset in margins, driven by increases in electric utility maintenance and natural gas distribution costs. Also included in the increase were operating costs associated with Fox Energy Center, acquired by WPS at the end of the first quarter of 2013, which are being recovered through a rate order.
- A $9.9 million after-tax decrease in natural gas utility margins due to the quarter-over-quarter impact of the reversal in 2013 of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 20, Regulatory Environment, for more information.
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- An $8.7 million after-tax decrease in IES's realized retail electric margins, driven by higher purchased power and ancillary services costs related to the colder weather.

- A $6.2 million decrease in net income from discontinued operations. See Note 5, Dispositions, for more information.

These decreases were partially offset by:

- The $26.3 million after-tax positive impact of rate orders at the utilities.

- A $17.3 million after-tax increase in natural gas utility margins due to an increase in sales volumes driven by colder weather, net of decoupling. Certain of our natural gas utilities did not have decoupling in 2014 to offset the impact of weather.

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Regulated Natural Gas Utility Segment Operations

	Three Months Ended March 31		Change in 2014
(Millions, except degree days)	2014	2013	Over 2013
Revenues	$1,272.0	$793.9	60.2 %
Purchased natural gas costs	830.4	424.1	95.8 %
Margins	441.6	369.8	19.4 %
Operating and maintenance expense	215.4	162.1	32.9 %
Depreciation and amortization expense	36.4	32.2	13.0 %
Taxes other than income taxes	10.8	9.9	9.1 %
Operating income	179.0	165.6	8.1 %
Miscellaneous income	0.3	0.2	50.0 %
Interest expense	13.4	12.7	5.5 %
Other expense	(13.1)	(12.5)	4.8 %
Income before taxes	$165.9	$153.1	8.4 %
Retail throughput in therms			
Residential	927.2	775.9	19.5 %
Commercial and industrial	301.4	236.8	27.3 %
Other	23.9	20.0	19.5 %
Total retail throughput in therms	1,252.5	1,032.7	21.3 %
Transport throughput in therms			
Residential	135.4	111.3	21.7 %
Commercial and industrial	618.9	551.6	12.2 %
Total transport throughput in therms	754.3	662.9	13.8 %
Total throughput in therms	2,006.8	1,695.6	18.4 %
Weather			
Average actual heating degree days	4,174	3,506	19.1 %
Average normal heating degree days	3,371	3,314	1.7 %

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 59% increase and an approximate 4% decrease in the average per-unit cost of natural gas sold during the first quarter of 2014 and 2013, respectively, which had no impact on margins.

First Quarter 2014 Compared with First Quarter 2013

Margins

Regulated natural gas utility segment margins increased $71.8 million, driven by:

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An approximate $30 million increase in margins related to certain riders at NSG and PGL and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

Our natural gas utilities billed approximately $18 million more to customers for energy efficiency programs at MERC, MGU, NSG, and PGL in 2014.

NSG and PGL recovered from their customers approximately $12 million more for environmental cleanup costs at their former manufactured gas plant sites due to an increase in sales volumes and an increase in remediation costs, net of insurance settlements received. See Note 11, Commitments and Contingencies, for more information about the manufactured gas plant sites.

- An approximate $29 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 June 27, 2013, but updated effective January 1, 2014, had an approximate $30 million positive impact on margins.

The rate increase at MGU, effective January 1, 2014, resulted in an approximate $1 million positive impact on margins.

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The interim rate increase at MERC, effective January 1, 2014, had an approximate $1 million positive impact on margins.

Margins were negatively impacted at WPS by approximately $3 million related to its rate order, effective January 1, 2014. The decrease in margins was driven by the quarter-over-quarter impact of the amortization of prior year decoupling deferrals. Rate design changes in 2014 also contributed to the decrease in margins. The new rate design includes higher fixed customer charges and lower volumetric charges, which will reduce fluctuations in margins throughout the year caused by seasonal use. The higher volumes sold in 2014 had less of an impact on margin as a result of the new rate design.

- An approximate $12 million net increase in margins due to sales volume variances and our decoupling mechanisms.

The combined effect of the change in weather quarter over quarter, the impact of higher weather-normalized volumes, and the impact of our decoupling mechanisms increased margins approximately $29 million. In 2014, margins at the natural gas utilities were positively impacted by colder than normal weather, net of decoupling impacts at MERC, NSG, and PGL. Effective January 1, 2014, MGU and WPS no longer have decoupling mechanisms in place. During the first quarter of 2014, MERC reached its maximum accrued refund to customers under the annual 10% cap provision of its decoupling mechanism. In 2013, decoupling mechanisms were in place for all the natural gas utilities, but colder than normal weather had a positive impact on MGU's margins as its decoupling mechanism did not cover weather-related volume variances. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 20, Regulatory Environment, for more information on our decoupling mechanisms.

Margins were negatively impacted quarter-over-quarter by approximately $17 million due to a reversal in 2013 of reserves established in 2012 against PGL and NSG regulatory assets related to decoupling. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 20, Regulatory Environment, for more information.

Operating Income

Operating income at the regulated natural gas utility segment increased $13.4 million. This increase was driven by the $71.8 million increase in margins discussed above, partially offset by a $58.4 million increase in operating expenses.

The increase in operating expenses was primarily due to:

- A $17.5 million increase in energy efficiency program expenses at our natural gas utilities. For the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $12.1 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. Margins increased by an equal amount, resulting in no impact on earnings.

- An $8.8 million increase in natural gas distribution costs, primarily at PGL. The increase was primarily due to increased labor and external costs driven by additional repairs and maintenance associated with the colder than normal weather in 2014.

- An $8.2 million increase in bad debt expense, driven by a cost of natural gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. This natural gas component is charged to customers based on actual volumes and natural gas prices. As a result of this component, bad debt expense was primarily impacted by both higher natural gas costs in 2014 and an increase in sales volumes. However, the increase in bad debt expense does not impact earnings as it is offset by higher rates through a rider mechanism, resulting in higher margins.

- A $4.2 million net increase in depreciation and amortization expense. Continued investment in property and equipment, primarily the accelerated natural gas main replacement program at PGL, drove the increase in expense. A $2.5 million reduction in expense in 2013 at MGU also contributed to the quarter-over-quarter increase in expense. In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010. See Note 20, Regulatory Environment, for more information.

- A $1.6 million increase in asset usage charges from IBS, driven by new software for both natural gas management and work asset management that was placed in service during the third quarter of 2013.

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Regulated Electric Utility Segment Operations

(Millions, except degree days)	Three Months Ended March 31 2014	2013	Change in 2014 Over 2013
Revenues	$349.2	$331.8	5.2 %
Fuel and purchased power costs	136.7	143.2	(4.5)%
Margins	212.5	188.6	12.7 %
Operating and maintenance expense	116.0	101.4	14.4 %
Depreciation and amortization expense	25.6	21.5	19.1 %
Taxes other than income taxes	12.8	12.8	— %
Operating income	58.1	52.9	9.8 %
Miscellaneous income	3.5	1.6	118.8 %
Interest expense	11.7	9.1	28.6 %
Other expense	(8.2)	(7.5)	9.3 %
Income before taxes	$49.9	$45.4	9.9 %
Sales in kilowatt-hours			
Residential	898.3	823.8	9.0 %
Commercial and industrial	2,077.9	2,072.0	0.3 %
Wholesale	684.8	1,046.6	(34.6)%
Other	10.6	10.7	(0.9)%
Total sales in kilowatt-hours	3,671.6	3,953.1	(7.1)%
Weather			
WPS:			
Actual heating degree days	4,515	3,803	18.7 %
Normal heating degree days	3,646	3,643	0.1 %
UPPCO:			
Actual heating degree days	4,884	4,087	19.5 %
Normal heating degree days	3,972	3,967	0.1 %

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 2014 Compared with First Quarter 2013

Margins

Regulated electric utility segment margins increased $23.9 million, driven by:

- An approximate $15 million increase in margins related to WPS and UPPCO rate orders effective January 1, 2014. See Note 20, Regulatory Environment, for more information.

Excluding the impacts from fuel and purchased power costs, the WPS PSCW rate order resulted in an approximate $15 million increase in margins. Although the PSCW approved an electric rate decrease, it was driven by refunds of 2013 fuel cost over-collections and 2012 decoupling over-collections, which have no impact on margins. The increase was driven by the inclusion of the costs of operating the Fox Energy Center.

UPPCO's retail electric rate increase resulted in an approximate $2 million increase in margins.

Partially offsetting these increases was an approximate $2 million decrease in margins related to WPS fuel and purchased power costs. The decrease was driven by fuel and purchased power cost under-collections in 2014, compared with fuel and purchased power cost over-collections in 2013. 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. WPS's fuel and purchased power costs that are not included in the recovery mechanism were lower than rate case-approved amounts, resulting in a partially offsetting increase in margins.

- An approximate $4 million increase in WPS's wholesale margins driven by higher prices. Wholesale prices increased primarily due to increased generation costs.

- An approximate $3 million net increase in margins from residential and commercial and industrial customers due to variances related to sales volumes, including the impact of decoupling. The increase was driven by colder than normal weather in 2014. Both WPS's and UPPCO's decoupling mechanisms were terminated effective January 1, 2014. See Note 20, Regulatory Environment, for more information.

Operating Income

Operating income at the regulated electric utility segment increased $5.2 million. The increase was driven by the $23.9 million increase in margins discussed above, partially offset by an $18.7 million increase in operating expenses. The increase in operating expenses was driven by:

- A $10.0 million increase in maintenance expense, primarily due to a major outage at the Pulliam plant in 2014, as well as maintenance at certain WPS generation plants.

- A $4.1 million increase in depreciation and amortization expense, mainly due to the acquisition of the Fox Energy Center at the end of the first quarter of 2013.

- A $3.6 million increase in electric transmission expense.

- A $2.9 million increase in various costs associated with the acquisition and operation of the Fox Energy Center. Included in this amount is the amortization of the regulatory asset related to the fee paid for the early termination of the power purchase agreement in connection with the acquisition. Margins increased by an amount equal to the amortization, resulting in no impact on earnings.

- A $1.6 million increase due to the quarter-over-quarter impact of WPS's 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, WPS did receive PSCW approval to defer ownership costs above or below its power purchase agreement expenses in 2013.

Partially offsetting these increases was a $7.1 million decrease in employee benefit expenses, driven by higher discount rates assumed in 2014. In 2013, WPS deferred certain components of its pension and other employee benefit costs as a result of its 2013 PSCW rate order. WPS began amortizing this regulatory asset in 2014. The quarter-over-quarter impact of the deferral and related amortization partially offset the decrease in employee benefit expenses by $3.6 million.

Other Expense

Other expense increased $0.7 million, driven by an increase in interest expense due to WPS's issuance of $450.0 million of long-term debt in November 2013. The increase in interest expense was partially offset by an increase in WPS's allowance for funds used during construction, largely due to environmental compliance projects at the Columbia plant.

Electric Transmission Investment Segment Operations

	Three Months Ended March 31	Change in 2014 Over

(Millions)	2014	2013	2013	
Earnings from equity method investments	$22.5	$21.7	3.7	%

First Quarter 2014 Compared with First Quarter 2013

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $0.8 million in the first quarter of 2014. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

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IES Nonregulated Segment Operations

IES has been able to take advantage of continued growth opportunities as evidenced by increasing volumes delivered and contracted for future delivery in certain markets. During the three months ended March 31, 2014, delivered electric and natural gas volumes grew approximately 47% and 73%, respectively, compared with the same period in 2013. In addition, IES's electric and natural gas volumes for future delivery grew by approximately 13% and 76%, respectively, from March 31, 2013 to March 31, 2014. However, sustained low commodity prices, capital costs, and market volatility have led to continued competitive pressure on per-unit margins.

(Millions, except natural gas sales volumes)	Three Months Ended March 31 2014	2013	Change in 2014 Over 2013
Revenues	$1,292.2	$545.7	136.8 %
Cost of sales	1,234.8	430.7	186.7 %
Margins	57.4	115.0	(50.1)%
Margin Detail			
Realized retail electric margins	9.4	23.9	(60.7)%
Realized renewable energy asset margins	2.6	3.0	(13.3)%
Fair value accounting adjustments	17.7	62.7	(71.8)%
Electric and renewable energy asset margins	29.7	89.6	(66.9)%
Realized retail natural gas margins	24.4 [2]	18.9	29.1 %
Realized wholesale natural gas margins [1]	(0.2)	0.2	N/A
Lower-of-cost-or-market inventory adjustments	1.6	4.0	(60.0)%
Fair value accounting adjustments	1.9	2.3	(17.4)%
Natural gas margins	27.7	25.4	9.1 %
Operating and maintenance expense	36.4	32.8	11.0 %
Depreciation and amortization expense	2.9	2.7	7.4 %
Taxes other than income taxes	1.2	1.0	20.0 %
Operating income	16.9	78.5	(78.5)%
Earnings from equity method investments	0.1	0.2	(50.0)%
Miscellaneous income	0.3	0.4	(25.0)%
Interest expense	0.5	0.5	— %
Other income (expense)	(0.1)	0.1	N/A
Income before taxes	$16.8	$78.6	(78.6)%
Physically settled volumes			
Retail electric sales volumes in kwh	6,356.9	4,318.2	47.2 %
Wholesale assets and distributed solar electric sales volumes in kwh	14.1	18.0	(21.7)%
Retail natural gas sales volumes in bcf	87.6	50.7	72.8 %

kwh — kilowatt-hours
bcf — billion cubic feet

[1] Realized wholesale activity relates to remaining contracts for which offsetting positions were entered into.

[2] This amount includes negative margins of $2.6 million related to the amortization of the net amount paid for customer and related supply contracts in connection with acquisitions.

First Quarter 2014 Compared with First Quarter 2013

Revenues

IES's revenues increased $746.5 million. The increase was driven by higher retail sales volumes, primarily related to the expansion of the residential and small commercial customer business as well as the Compass Energy Services acquisition in May 2013. Higher average commodity prices and increased usage in 2014 related to the colder weather also contributed to the increase in revenues.

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Margins

IES's margins decreased $57.6 million. Significant items contributing to the change in margins were as follows:

Electric and Renewable Energy Asset Margins

Realized retail electric margins

Realized retail electric margins decreased $14.5 million. The decrease was primarily driven by an approximate $6 million increase in costs related to certain ancillary services charged by independent system operators in January 2014 due to the colder weather. In addition, sales volumes for fixed-price full requirements customers increased significantly due to the colder weather, requiring IES to purchase power at high market prices to meet this unexpected demand. Continued competitive pressure on per-unit margins also contributed to the decrease in margins.

Fair value accounting adjustments

Derivative accounting rules impact IES's margins. Fair value adjustments caused a $45.0 million decrease in electric margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins increased $5.5 million. The increase was primarily driven by colder weather quarter over quarter. Higher sales volumes, primarily related to the expansion of the residential and small commercial customer business as well as the Compass Energy Services acquisition in May 2013, also contributed to the increase in margins. These increases were partially offset by continued competitive pressure on per-unit margins. Realized retail natural gas margins include the amortization of customer and supply contracts related to the acquisition of Compass Energy Services.

Inventory accounting adjustments

IES's physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $2.4 million quarter-over-quarter decrease in margins from inventory adjustments was driven by a lower volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Operating Income

IES's operating income decreased $61.6 million. The main driver of the decrease was the $57.6 million decrease in margins discussed above. In addition, operating expenses increased $4.0 million. The increase in operating expenses was primarily driven by an increase in costs related to the Compass Energy Services acquisition in May 2013, as well as the expansion of the residential and small commercial customer business.

Holding Company and Other Segment Operations

(Millions)	Three Months Ended March 31 2014	2013	Change in 2014 Over 2013
Operating loss	$(0.8)	$(3.9)	(79.5)%
Other expense	(11.3)	(3.1)	264.5%
Loss before taxes	$(12.1)	$(7.0)	72.9%

First Quarter 2014 Compared with First Quarter 2013

Operating Loss

Operating loss at the holding company and other segment decreased $3.1 million. The decrease was primarily driven by a $1.6 million decrease in operating losses at ITF.

Other Expense

Other expense at the holding company and other segment increased $8.2 million. The increase was primarily due to a $6.4 million increase in interest expense on long-term debt, driven by the issuance of $400.0 million of Junior Subordinated Notes during August 2013. Also contributing to

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the increase was the $2.1 million quarter-over-quarter negative impact of excise tax credits recorded at ITF in 2013 as a result of the American Taxpayer Relief Act of 2012. These excise tax credits were not available in 2014.

Provision for Income Taxes

	Three Months Ended March 31	
	2014	2013
Effective tax rate	37.0 %	37.6 %

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

Discontinued Operations

(Millions)	Three Months Ended March 31 2014	2013	Change in 2014 Over 2013
Discontinued operations, net of tax	$(0.1)	$6.1	N/A

First Quarter 2014 Compared with First Quarter 2013

Earnings from discontinued operations, net of tax, decreased $6.2 million in 2014. In the first quarter of 2013, we remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling a certain state income tax examination. We reduced the provision for income taxes related to this remeasurement, of which the majority was reported as discontinued operations.

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, 2014, net cash provided by operating activities was $263.3 million, compared with $319.6 million during the same quarter in 2013. The $56.3 million decrease in net cash provided by operating activities was driven by:

- An $882.8 million decrease in cash related to higher costs of natural gas, fuel, and purchased power in 2014. The decrease was driven by higher energy prices and colder than normal weather in the first quarter of 2014. Of this variance, $170.6 million relates to under-collections from regulated utility customers. These under-collections were higher in 2014 than in 2013. To meet the higher energy needs of customers, we purchased natural gas, fuel, and purchased power at higher prices than expected in 2014, which were not yet reflected in the rates charged to our customers.

- A $73.8 million decrease in cash related to increased operating and maintenance costs in 2014. The decrease was driven by increases in electric utility maintenance, natural gas distribution costs, and operating costs associated with the Fox Energy Center, which was acquired by WPS at the end of the first quarter of 2013.

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A $52.4 million decrease in cash driven by higher collateral requirements in 2014 compared with 2013 at IES. Collateral requirements are based on forward natural gas and electricity prices and forward positions with counterparties.

- An $8.6 million increase in cash paid for interest, primarily driven by an increase in long-term debt in 2014 as compared with 2013.
- A $5.4 million increase in contributions to pension and other postretirement benefit plans.

These decreases in cash were partially offset by:

- An $830.7 million increase in cash collections from customers, mainly due to rate increases at the regulated utilities and the colder than normal weather in 2014.
- A $61.7 million increase in cash received from income taxes, primarily driven by a federal income tax refund received in the first quarter of 2014 for an amended return.
- The positive quarter-over-quarter impact of a $50.0 million payment in 2013 for WPS's early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

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- A $17.6 million increase in cash related to customer prepayments and credit balances. In the first quarter of 2013, cash received in relation to amounts billed was lower because customer prepayments had grown during an unusually warm 2012.

Investing Cash Flows

During the three months ended March 31, 2014, net cash used for investing activities was $163.3 million, compared with $473.2 million during the same quarter in 2013. The $309.9 million decrease in net cash used for investing activities was primarily due to $391.6 million of cash used in 2013 for WPS's purchase of Fox Energy Company LLC. See Note 4, Acquisitions, for more information regarding this purchase. Partially offsetting the decrease in net cash used was the quarter-over-quarter negative impact of the receipt of a $69.0 million Section 1603 Grant for the Crane Creek wind project in 2013 and a $12.6 million increase in cash used for other capital expenditures (discussed below).

Capital Expenditures

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

Reportable Segment (millions)	2014	2013	Change
Natural gas utility	$68.2	$85.8	$(17.6)
Electric utility	55.7	439.9	(384.2)
IES	7.5	3.4	4.1
Holding company and other	28.2	9.5	18.7
Integrys Energy Group consolidated	$159.6	$538.6	$(379.0)

The decrease in capital expenditures at the natural gas utility segment in 2014 compared with 2013 was primarily due to colder weather conditions impacting work on the accelerated natural gas main replacement program at PGL.

The decrease in capital expenditures at the electric utility segment in 2014 compared with 2013 was primarily due to WPS's purchase of Fox Energy Company LLC in 2013. Capital expenditures related to environmental compliance projects at the Columbia Plant also decreased in 2014. Increased expenditures at the electric utility segment related to the ReACT™ project at Weston 3 in 2014 partially offset the decrease.

Finally, capital expenditures at the holding company and other segment increased in 2014 compared with 2013, primarily due to increased expenditures for software projects and office leasehold improvements.

Financing Cash Flows

During the three months ended March 31, 2014, net cash used for financing activities was $72.1 million, compared with net cash provided by financing activities of $197.2 million during the same quarter in 2013. The $269.3 million quarter-over-quarter change was driven by:

- A $200.0 million decrease in borrowings under WPS's term credit facility, which were used in 2013 to partially finance the acquisition of Fox Energy Company LLC.

- A $78.1 million decrease in cash due to $4.1 million of net repayments of commercial paper in 2014, compared with $74.0 million of net borrowings of commercial paper in 2013.

- A $7.8 million increase in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. We began purchasing shares of our common stock on the open market starting in February 2014 as well as during a short period during the first quarter of 2013.

These decreases in cash were partially offset by the quarter-over-quarter impact of a $22.0 million repayment of long-term debt in 2013.

Significant Financing Activities

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 02/05/2014	Purchasing shares on the open market
02/05/2013 – 02/05/2014	Issued new shares
01/01/2012 – 02/04/2013	Purchased shares on the open market

For information on short-term debt, see Note 9, Short-Term Debt and Lines of Credit.

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There were no significant changes in long-term debt during the first quarter of 2014.

Credit Ratings

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

Credit Ratings	Standard & Poor's	Moody's
Integrys Energy Group		
Issuer credit rating	A-	N/A
Senior unsecured debt	BBB+	Baa1
Commercial paper	A-2	P-2
Junior subordinated notes	BBB	Baa2
WPS		
Issuer credit rating	A-	A1
First mortgage bonds	N/A	Aa2
Senior secured debt	A	Aa2
Preferred stock	BBB	A3
Commercial paper	A-2	P-1
PGL		
Issuer credit rating	A-	A2
Senior secured debt	A	Aa3
Commercial paper	A-2	P-1
NSG		
Issuer credit rating	A-	A2
Senior secured debt	A	Aa3

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

On January 31, 2014, Moody's confirmed the credit ratings for Integrys Energy Group and raised the credit ratings for WPS, PGL, and NSG. The issuer rating was raised to "A1" from "A2" for WPS and to "A2" from "A3" for both PGL and NSG. WPS's first mortgage bonds rating was raised to "Aa2" from "Aa3." The senior secured debt rating was raised to "Aa2" from "Aa3" for WPS and to "Aa3" from "A1" for both PGL and NSG. The preferred stock rating for WPS was raised to "A3" from "Baa1." Finally, PGL's commercial paper rating was raised to "P-1" from "P-2." The upgrade in ratings of the utilities reflects Moody's views of the regulatory provisions in Wisconsin and Illinois that are consistent with a generally improving regulatory environment for electric and natural gas utilities in the United States.

Discontinued Operations

These cash flows primarily relate to the operations of WPS Beaver Falls Generation, LLC, WPS Syracuse Generation, LLC, and Combined Locks Energy Center, LLC. See Item 2 – Management's Discussion and Analysis of Financial Condition and Results of Operations, Discontinued Operations, and Note 5, Dispositions, for more information.

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Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of March 31, 2014, including those of our subsidiaries:

	Payments Due By Period				
(Millions)	Total Amounts Committed	2014	2015 to 2016	2017 to 2018	2019 and Later Years
Long-term debt principal and interest payments [(1)]	$ 7,322.0	$ 209.6	$ 506.0	$ 382.1	$ 6,224.3
Operating lease obligations	92.4	4.9	13.1	15.0	59.4
Energy and transportation purchase obligations [(2)]	2,407.2	611.4	671.9	321.7	802.2
Purchase orders [(3)]	1,163.3	1,028.0	124.9	3.1	7.3
Capital contributions to equity method investment	5.1	5.1	—	—	—
Pension and other postretirement funding obligations [(4)]	48.2	15.6	32.6	—	—
Uncertain tax positions	0.7	0.7	—	—	—
Total contractual cash obligations	$ 11,038.9	$ 1,875.3	$ 1,348.5	$ 721.9	$ 7,093.2

(1) Represents bonds and notes issued, as well as loans made to us and our subsidiaries. We record all principal obligations on the balance sheet. For purposes of this table, it is assumed that the current interest rates on variable rate debt will remain in effect until the debt matures.

(2) Energy and related commodity supply contracts at IES included as part of energy and transportation purchase obligations are primarily entered into to meet future obligations to deliver energy and related products to customers; therefore, these costs will be recovered as customer sales contracts settle. The utility subsidiaries expect to recover the costs of their contracts in future customer rates.

(3) Includes obligations related to normal business operations and large construction obligations.

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2016.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $588.2 million at March 31, 2014, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 11, Commitments and Contingencies, for more information about environmental liabilities. The table also does not reflect estimated future payments for the March 31, 2014 liability of $1.6 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 10, Income Taxes, for more information about unrecognized tax benefits.

Capital Requirements

Projected capital expenditures by segment for 2014 through 2016, including amounts expended through March 31, 2014, are as follows:

(Millions)	2014	2015	2016	Total
Natural Gas Utility				
Distribution and transmission projects and underground storage facilities	$ 556	$ 478	$ 481	$ 1,515

Other projects	30	34	23	87
Electric Utility [1]				
Distribution and energy supply operations projects	139	137	131	407
Environmental projects [2]	140	135	105	380
Other projects	18	21	167	206
IES				
Renewable energy and other projects	68	42	42	152
Holding Company and Other				
Corporate or shared services software and infrastructure projects	68	31	40	139
Compressed natural gas fueling stations	32	44	45	121
Repairs and safety measures at nonutility hydroelectric facilities [1]	—	—	1	1
Total capital expenditures	$1,051	$922	$1,035	$3,008

(1) Approximately $31 million of projected capital expenditures relates to UPPCO. See Note 5, Dispositions, for more information on the pending sale of UPPCO.

(2) This primarily relates to the installation of ReACT™ emission control technology at Weston 3 and the installation of scrubbers at the Columbia plant.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $56 million from 2014 through 2016.

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All projected capital and investment expenditures are subject to periodic review and may vary significantly from the estimates, depending on a number of factors. These factors include, but are not limited to, environmental requirements, regulatory constraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends.

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management strategies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage our liquidity and capital resource needs. We plan to meet our capital requirements for the period 2014 through 2016 primarily through internally generated funds (net of forecasted dividend payments), dividends from our subsidiaries, and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

Under an existing shelf registration statement, we may issue debt, equity, certain types of hybrid securities, and other financial instruments with amounts, prices, and terms to be determined at the time of future offerings.

WPS currently has two shelf registration statements. Under these registration statements, WPS may issue up to $50.0 million of additional senior debt securities and up to $30.0 million of preferred stock. Amounts, prices, and terms will be determined at the time of future offerings.

At March 31, 2014, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future.

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 regulated utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 15, Common Equity, for more information on dividend restrictions.

Other Future Considerations

Presque Isle System Support Resources (SSR) Costs

In August 2013, Wisconsin Electric Power Company (Wisconsin Electric) submitted to MISO a notice, in which Wisconsin Electric stated its intention to suspend the operation of Units 5 through 9 of its Presque Isle generating facility for 16 months, starting February 1, 2014. MISO completed its reliability analysis and notified Wisconsin Electric in October 2013 that the Presque Isle facilities are required for reliability and would be SSR-designated until alternatives could be implemented to mitigate reliability issues. The SSR Tariff provisions permit MISO to negotiate compensation for generation resources where a market participant desires to retire or suspend operation of the facility but MISO determines that it is needed to maintain system reliability. In exchange for keeping the units in service, MISO will compensate Wisconsin Electric by allocating the SSR costs associated with the operation of the Presque Isle units to regulated and nonregulated load serving entities, including WPS, UPPCO, and IES, based on load ratio share within the ATC footprint. In January 2014, MISO submitted a new rate schedule to the FERC reflecting this. The allocated SSR costs for WPS are estimated at $9 million annually, which could change based on a filing by the PSCW to the FERC in April 2014 to change the allocation methodology to the various parties. In April 2013, the PSCW ordered that SSR costs for WPS retail customers should be deferred until December 31, 2015. At that time, the

PSCW will determine the appropriate ratemaking treatment. SSR costs for Michigan customers, including UPPCO and WPS, will be recovered from customers through the Power Supply Cost Recovery mechanism. Allocated SSR costs for IES can be passed through to customers.

MISO Transmission Owner Return on Equity Complaint

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting to, among other things, reduce the base return on equity used by MISO transmission owners, including ATC, to 9.15%. ATC's current authorized return on equity is 12.2%. Any change to ATC's return on equity and capital structure could result in lower equity income and dividends from ATC in the future. We are currently unable to determine the timing and nature of any FERC actions related to this complaint and resulting changes to our financial condition and results of operations.

Wisconsin Fuel Rule Under-collection "Cap"

WPS uses a "fuel window" mechanism to recover fuel and purchased power costs for its Wisconsin retail electric operations. Under the fuel window rule, actual fuel and purchased power costs that exceed a 2% variance from costs included in the rates charged to customers are deferred for recovery or refund. However, if the deferral of costs in a given year would cause WPS to earn a greater return on common equity than authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount the return exceeds that authorized by the PSCW. This is a possibility in any given year, and at this time it is unknown whether this provision of the fuel rule will impact WPS in the current year.

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Decoupling

In 2012, the Illinois Attorney General and Citizens Utility Board appealed the ICC's authority to approve PGL's and NSG's permanent decoupling mechanism. As a result, revenues collected under this mechanism were potentially subject to refund. In 2012, PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Illinois Appellate Court affirmed the ICC's authority to approve the permanent decoupling mechanism. Therefore, the reserves recorded in 2012 were reversed in the first quarter of 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Court's decision. The Illinois Supreme Court granted the request in September 2013, and briefing is in progress. The Illinois Supreme Court has no deadline by which it must act. Decoupling amounts recorded in 2012 were fully recovered and amounts in 2013 will be refunded to customers in 2014. Decoupling amounts in 2014 will continue to be accrued, absent an adverse Illinois Supreme Court decision.

See Note 20, Regulatory Environment, for more information on all of our subsidiaries' decoupling mechanisms.

Climate Change

The EPA began regulating greenhouse gas emissions under the Clean Air Act in January 2011 by applying the Best Available Control Technology (BACT) requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In March 2012, the EPA issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units. The proposed limit may prevent the construction of new coal units until technology becomes commercially available.

In September 2013, the EPA re-proposed rules related to emission limits on new electric generating units, and the EPA is expected to finalize them in a timely manner. The EPA was also directed to propose a rule for existing units by no later than June 1, 2014, and issue a final rule by June 1, 2015, with state implementation plans due by June 30, 2016. Facility compliance deadlines will be included in the final state plans.

A risk exists that any greenhouse gas legislation or regulation will increase the cost of producing energy using fossil fuels. However, we believe that capital expenditures being made at our plants are appropriate under any reasonable mandatory greenhouse gas program. We also believe that our future expenditures that may be required to control greenhouse gas emissions or meet renewable portfolio standards will be recoverable in rates. We will continue to monitor and manage potential risks and opportunities associated with future greenhouse gas legislative or regulatory actions.

The majority of our generation and distribution facilities are located in the upper Midwest region of the United States. The same is true for most of our customers' facilities. The physical risks, if any, posed by climate change for this area are not expected to be significant at this time. Ongoing evaluations will be conducted as more information on the extent of such physical changes becomes available.

Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act)

The Dodd-Frank Act was signed into law in July 2010. The final Commodity Futures Trading Commission (CFTC) rulemakings, which are essential to the Dodd-Frank Act's new framework for swaps regulation, have become effective or are becoming effective for certain companies and certain transactions. Some of the rules have not been finalized yet, are being challenged in court, or are subject to ongoing interpretations, clarifications, no-action letters, and other guidance being issued by the CFTC and its staff. As a result, it is difficult to predict how the CFTC's final Dodd-Frank Act rules will ultimately affect us. Certain provisions of the Dodd-Frank Act relating to derivatives could significantly increase our regulatory costs and/or collateral requirements, including our derivatives, which we use to hedge our commercial risks.

We continue to monitor developments related to the Dodd-Frank Act rulemakings and their potential impacts on our future financial results and have implemented the applicable requirements of the Dodd-Frank Act rules that have taken effect. For example, we have addressed certain requirements applicable to transaction reporting and have implemented an internal governance structure. We have also taken the necessary steps to qualify as an end user, which provides for an exemption related to mandatory clearing. Lastly, we have made the necessary systems and process changes to comply with the rules within the CFTC's implementation timelines.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies and considered whether any new critical accounting estimates or other significant changes to our accounting policies require any additional disclosures. We have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2013, are still current and that there have been no significant changes.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

We have potential market risk exposure related to commodity price risk, interest rate risk, and equity return and principal preservation risk. We are also exposed to other significant risks due to the nature of our subsidiaries' businesses and the environment in which we operate. We have risk management policies in place to monitor and assist in controlling these risks, and we use derivative and other instruments to manage some of these exposures, as further described below.

Commodity Price Risk

To measure commodity price risk exposure, we employ a number of controls and processes, including a value-at-risk (VaR) analysis of certain of our exposures. IES's VaR is calculated using nondiscounted positions with a delta-normal approximation based on a ten-day holding period and a 99% confidence level. For further explanation of our VaR calculation, see our 2013 Annual Report on Form 10-K.

The VaR for IES's open commodity positions at a 99% confidence level with a ten-day holding period is presented below:

(Millions)	2014	2013
As of March 31	$1.2	$0.7
Average for 12 months ended March 31	1.0	0.6
High for 12 months ended March 31	1.2	0.7
Low for 12 months ended March 31	0.6	0.4

The average, high, and low amounts were computed using the VaR amounts at each of the four quarter ends.

Interest Rate Risk

We are exposed to interest rate risk resulting from our short-term borrowings and projected near-term debt financing needs. We manage exposure to interest rate risk by limiting the amount of variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at March 31, 2014, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.2 million. Comparatively, based on the variable rate debt outstanding at March 31, 2013, an increase in interest rates of 100 basis points would have increased annual interest expense by $7.6 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Other than the above-mentioned changes, our market risks have not changed materially from the market risks reported in our 2013 Annual Report on Form 10-K.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of Integrys Energy Group's disclosure controls and procedures (as defined by Securities Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based upon that evaluation, management, including our Chief Executive Officer and Chief Financial Officer, has concluded that Integrys Energy Group's disclosure controls and procedures were effective as of the end of the period covered by this report.

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended March 31, 2014, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2013 Annual Report on Form 10-K, which was filed with the SEC on February 27, 2014.

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

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. See Note 15, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends.

Issuer Purchases of Equity Securities

As of February 5, 2014, we began purchasing shares in the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. Prior to this date, we issued new shares of common stock to meet the requirements of these plans. The following table provides a summary of common stock purchases for the three months ended March 31, 2014:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
01/01/14 – 01/31/14 *	—	$—	—	—
02/01/14 – 02/28/14 *	127,365	55.31	—	—
03/01/14 – 03/31/14 *	75,335	57.32	—	—
Total	202,700	$56.06	—	—

* Represents shares of common stock purchased on the open market by American Stock Transfer & Trust Company to provide shares of common stock to participants in the Stock Investment Plan and to satisfy obligations under various stock-based employee benefit and compensation plans.

Item 6. Exhibits

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

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SIGNATURE

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

	INTEGRYS ENERGY GROUP, INC. (Registrant)
Date: May 2, 2014	/s/ Linda M. Kallas Linda M. Kallas Vice President and Controller (Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS ENERGY GROUP
EXHIBIT INDEX TO FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2014

Exhibit No.	Description
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended March 31, 2014, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Statements of Comprehensive Income, (iii) the Condensed Consolidated Balance Sheets, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity information.