INTEGRYS ENERGY GROUP, INC.
Form 10-Q
August 07, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2014

OR

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

For the transition period from __________ to __________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-11337	INTEGRYS ENERGY GROUP, INC. (A Wisconsin Corporation) 200 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

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

Yes [X] No [ ]

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

Yes [X] No [ ]

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

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

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

Yes [ ]   No [X]

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

Common stock, $1 par value,
79,963,091 shares outstanding at
August 5, 2014

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For the Quarter Ended June 30, 2014
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Acronyms Used in this Quarterly Report on Form 10-Q

AFUDC	Allowance for Funds Used During Construction
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 possibility that the proposed merger with Wisconsin Energy Corporation (Wisconsin Energy) does not close (including, but not limited to, due to the failure to satisfy the closing conditions), disruption from the proposed merger making it more difficult to maintain our business and operational relationships, and the risk that unexpected costs will be incurred during this process;
- The risk that we may not complete the sales of IES and UPPCO;
- 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 (such as the proposed merger with Wisconsin Energy and the pending sales of IES and UPPCO);
- 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		Six Months Ended	
	June 30		June 30	
(Millions, except per share data)	2014	2013	2014	2013
Utility revenues	$806.1	$694.4	$2,422.8	$1,818.2
Nonregulated revenues	626.5	421.6	1,934.7	976.0
Total revenues	1,432.6	1,116.0	4,357.5	2,794.2
Utility cost of fuel, natural gas, and purchased power	383.0	296.0	1,343.2	861.1
Nonregulated cost of sales	576.5	447.9	1,824.0	884.7
Operating and maintenance expense	334.3	288.7	698.9	583.8
Goodwill impairment loss	6.7	—	6.7	—
Merger transaction costs	5.9	—	5.9	—
Transaction costs related to pending sale of UPPCO	0.9	—	0.9	—
Transaction costs related to pending sale of IES retail energy business	0.8	—	0.8	—
Depreciation and amortization expense	72.9	65.5	144.2	126.4
Taxes other than income taxes	25.5	24.8	53.6	52.0
Operating income (loss)	26.1	(6.9)	279.3	286.2
Earnings from equity method investments	23.9	22.8	46.8	45.1
Miscellaneous income	5.0	5.5	11.0	11.2
Interest expense	38.7	28.6	77.8	57.9
Other expense	(9.8)	(0.3)	(20.0)	(1.6)
Income (loss) before taxes	16.3	(7.2)	259.3	284.6
Provision (benefit) for income taxes	8.2	(3.3)	98.0	106.3
Net income (loss) from continuing operations	8.1	(3.9)	161.3	178.3
Discontinued operations, net of tax	(0.1)	(0.8)	(0.2)	5.3
Net income (loss)	8.0	(4.7)	161.1	183.6
Preferred stock dividends of subsidiary	(0.8)	(0.8)	(1.6)	(1.6)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Net income (loss) attributed to common shareholders	$7.2	$(5.4)	$159.6	$182.1
Average shares of common stock				
Basic	80.2	79.4	80.2	79.0
Diluted	80.5	79.4	80.5	79.7
Earnings (loss) per common share (basic)				
Net income (loss) from continuing operations	$0.09	$(0.06)	$1.99	$2.24
Discontinued operations, net of tax	—	(0.01)	—	0.07

Earnings (loss) per common share (basic)	$0.09	$(0.07)	$1.99	$2.31
Earnings (loss) per common share (diluted)				
Net income (loss) from continuing operations	$0.09	$(0.06)	$1.98	$2.22
Discontinued operations, net of tax	—	(0.01)	—	0.07
Earnings (loss) per common share (diluted)	$0.09	$(0.07)	$1.98	$2.29
Dividends per common share declared	$0.68	$0.68	$1.36	$1.36

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		Six Months Ended	
	June 30		June 30	
(Millions)	2014	2013	2014	2013
Net income (loss)	$8.0	$(4.7)	$161.1	$183.6
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net gains arising during period, net of tax of an insignificant amount for all periods presented	—	0.6	—	0.7
Reclassification of net losses (gains) to net income, net of tax of $ – million, $0.9 million, $0.9 million, and $1.5 million, respectively	0.2	1.5	(0.4)	2.4
Cash flow hedges, net	0.2	2.1	(0.4)	3.1
Defined benefit plans				
Pension and other postretirement benefit costs arising during period, net of tax of an insignificant amount for all periods presented	—	—	(0.1)	—
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.2 million, $0.4 million, $0.5 million, and $0.8 million, respectively	0.5	0.6	0.8	1.2
Defined benefit plans, net	0.5	0.6	0.7	1.2
Other comprehensive income, net of tax	0.7	2.7	0.3	4.3
Comprehensive income (loss)	8.7	(2.0)	161.4	187.9
Preferred stock dividends of subsidiary	(0.8)	(0.8)	(1.6)	(1.6)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Comprehensive income (loss) attributed to common shareholders	$7.9	$(2.7)	$159.9	$186.4

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)	June 30	December 31
(Millions, except share and per share data)	2014	2013
Assets		
Cash and cash equivalents	$45.0	$ 22.3
Accounts receivable and accrued unbilled revenues, net of reserves of $66.6 and $49.4, respectively	925.6	1,037.0
Inventories	223.8	253.1
Assets from risk management activities	253.4	239.5
Regulatory assets	119.4	127.4
Assets held for sale	290.4	272.6
Deferred income taxes	35.9	31.4
Prepaid taxes	72.7	146.9
Other current assets	72.2	87.4
Current assets	2,038.4	2,217.6
Property, plant, and equipment, net of accumulated depreciation of $3,325.0 and $3,236.9, respectively	6,444.5	6,216.7
Regulatory assets	1,337.5	1,361.4
Assets from risk management activities	88.3	75.4
Equity method investments	559.6	540.9
Goodwill	655.4	662.1
Other long-term assets	250.7	169.4
Total assets	$11,374.4	$ 11,243.5
Liabilities and Equity		
Short-term debt	$420.7	$ 326.0
Current portion of long-term debt	—	100.0
Accounts payable	599.2	604.8
Liabilities from risk management activities	167.9	163.8
Accrued taxes	53.4	80.9
Regulatory liabilities	126.0	101.1
Liabilities held for sale	43.0	49.1
Other current liabilities	262.1	228.8
Current liabilities	1,672.3	1,654.5
Long-term debt	2,956.2	2,956.2
Deferred income taxes	1,482.8	1,390.3
Deferred investment tax credits	60.0	57.6
Regulatory liabilities	437.3	383.7
Environmental remediation liabilities	576.3	600.0
Pension and other postretirement benefit obligations	118.2	200.8
Liabilities from risk management activities	61.1	62.8
Asset retirement obligations	503.4	491.0
Other long-term liabilities	147.3	133.2
Long-term liabilities	6,342.6	6,275.6
Commitments and contingencies		

Common stock – $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,529,584 shares outstanding	80.0	79.9
Additional paid-in capital	2,654.7	2,660.5
Retained earnings	617.6	567.1
Accumulated other comprehensive loss	(22.9)	(23.2)
Shares in deferred compensation trust	(21.1)	(23.0)
Total common shareholders' equity	3,308.3	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	0.1	1.0
Total liabilities and equity	$11,374.4	$ 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)

	Six Months Ended June 30	
(Millions)	2014	2013
Operating Activities		
Net income	$161.1	$183.6
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	0.2	(5.3)
Goodwill impairment loss	6.7	—
Depreciation and amortization expense	144.2	126.4
Recoveries and refunds of regulatory assets and liabilities	59.1	28.8
Net unrealized (gains) losses on energy contracts	(24.8)	0.3
Bad debt expense	30.8	14.4
Pension and other postretirement expense	11.9	31.8
Pension and other postretirement contributions	(69.5)	(64.2)
Deferred income taxes and investment tax credits	83.1	144.0
Equity income, net of dividends	(9.5)	(9.6)
Termination of tolling agreement with Fox Energy Company LLC	—	(50.0)
Other	12.8	13.3
Changes in working capital		
Collateral on deposit	(1.5)	(19.6)
Accounts receivable and accrued unbilled revenues	89.0	19.8
Inventories	29.7	69.8
Other current assets	41.0	(54.0)
Accounts payable	(16.2)	41.3
Temporary LIFO liquidation credit	57.9	33.4
Other current liabilities	(20.0)	(56.2)
Net cash provided by operating activities	586.0	448.0
Investing Activities		
Capital expenditures	(348.6)	(300.1)
Capital contributions to equity method investments	(10.2)	(6.8)
Rabbi trust funding related to potential change in control	(65.0)	—
Acquisition of Fox Energy Company LLC	—	(391.6)
Acquisitions at IES	—	(12.4)
Grant received related to Crane Creek wind project	—	69.0
Other	(6.0)	(2.5)
Net cash used for investing activities	(429.8)	(644.4)
Financing Activities		
Short-term debt, net	94.7	150.8
Borrowing on term credit facility	—	200.0
Issuance of long-term debt	—	104.0
Repayment of long-term debt	(100.0)	(187.0)
Proceeds from stock option exercises	11.9	31.2
Shares purchased for stock-based compensation	(28.7)	(2.0)
Payment of dividends		
Preferred stock of subsidiary	(1.6)	(1.6)
Common stock	(108.2)	(100.7)

Other	(8.2)	(7.4)
Net cash (used for) provided by financing activities	(140.1)	187.3
Change in cash and cash equivalents – continuing operations	16.1	(9.1)
Change in cash and cash equivalents – discontinued operations		
Net cash provided by operating activities	6.6	0.3
Net cash provided by investing activities	—	1.6
Net change in cash and cash equivalents	22.7	(7.2)
Cash and cash equivalents at beginning of period	22.3	27.4
Cash and cash equivalents at end of period	$45.0	$20.2
Cash paid for interest	$74.5	$57.1
Cash received for income taxes	$(59.2)	$(1.3)

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

INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS (Unaudited)
June 30, 2014

Note 1—Basis of Presentation

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

We prepare our financial statements in conformity with the rules and regulations of the SEC for Quarterly Reports on Form 10-Q and in accordance with GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 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 4, Dispositions, for more information on the pending sale of UPPCO.

Note 2—Proposed Merger with Wisconsin Energy Corporation

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

The combined entity will be named WEC Energy Group, Inc. and will serve more than 4.3 million total natural gas and electric customers across Wisconsin, Illinois, Michigan, and Minnesota.

This transaction was approved unanimously by the Boards of Directors of both companies. It is subject to approvals from the shareholders of both companies, the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. The transaction also is subject to the notification and clearance and reporting requirements under the Hart-Scott-Rodino Act and other customary closing conditions. We expect the transaction to close in the summer of 2015.

Note 3—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 $14 million. We anticipate closing on this transaction by the end of the first quarter of 2015. 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 9, 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 22, 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 4—Dispositions

Dispositions

IES Segment – Pending Sale of IES Retail Energy Business

In July 2014, we entered into an agreement to sell the retail energy business portion of IES to Exelon Generation Company, LLC (Exelon) for $60.0 million plus adjusted net working capital at the time of the close. For informational purposes, in the sale agreement the adjusted net working capital balance was calculated at approximately $183 million as of May 31, 2014. Any accounting gain or loss on the sale will be dependent on the fair value of derivative assets and liabilities at the time of sale.

The transaction is conditioned on approval by FERC and is subject to the notification and reporting requirements under the Hart-Scott-Rodino Act. We expect the sale to be completed in the fourth quarter of 2014 or in the first quarter of 2015. After the close of the sale, we will provide certain transition services at cost to Exelon for up to 15

months.

The retail energy business consists of mostly financial assets and liabilities; therefore, it does not qualify as held for sale under the applicable accounting guidance.

The June 2014 announcement of the potential sale triggered an interim goodwill impairment test. See Note 9, Goodwill and Other Intangible Assets, for more information.

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 has been approved by all applicable state regulatory commissions but is still subject to approval by the FERC. This sale is expected to close in the third quarter of 2014. Following the sale, we will provide certain administrative and operational services to UPPCO during a transition period of 18 to 30 months.

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The pending sale of UPPCO does not meet the requirements under the applicable accounting guidance to qualify as discontinued operations as WPS will have significant continuing cash flows related to certain power purchase transactions that will continue as an external transaction 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)	June 30, 2014	December 31, 2013
Current assets	$24.6	$26.5
Property, plant, and equipment, net of accumulated depreciation of $90.5 and $88.9, respectively	193.3	193.8
Other long-term assets	71.8	51.6
Total assets	$289.7	$271.9
Current liabilities	$13.8	$16.7
Long-term liabilities	29.2	32.4
Total liabilities	$43.0	$49.1

In addition to the amounts above, intercompany payables of $2.2 million and $1.6 million at June 30, 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 as an external transaction with WPS after the sale, as discussed above.

Discontinued Operations

Holding Company and Other Segment

During the three months ended June 30, 2013, we recorded $0.1 million of after-tax losses in discontinued operations at the holding company and other segment. During the six months ended June 30, 2013, we recorded $5.9 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 state income tax examination. We reduced the provision for income taxes related to this remeasurement.

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.

Combined Locks had $0.7 million of assets that were classified as held for sale on the balance sheets at June 30, 2014, and December 31, 2013, which included inventories and property, plant, and equipment. During the three months ended June 30, 2014, and 2013, IES recorded after-tax losses of $0.1 million and $0.7 million, respectively, in discontinued operations related to Combined Locks. During the six months ended June 30, 2014, and 2013, IES recorded after-tax losses of $0.2 million and $0.8 million, respectively, in discontinued operations related to Combined Locks.

IES Segment – 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 six months ended June 30, 2013, IES recorded after-tax earnings of $0.2 million in discontinued operations related to the gain on sale, partially offset by a net loss from operations at Beaver Falls and Syracuse.

Note 5—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:

	Six Months Ended June 30	
(Millions)	2014	2013
Construction costs funded through accounts payable	$123.3	$81.8
Equity issued for employee stock ownership plan	1.7	6.7
Equity issued for stock-based compensation plans	—	16.0
Equity issued for reinvested dividends	—	6.1
Contingent consideration and payables related to the acquisition of Compass Energy Services	—	9.1

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At June 30, 2014, restricted cash recorded within other long-term assets on our balance sheet included $65.0 million that was transferred to the rabbi trust, triggered by the proposed merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on the merger. See Note 15, Employee Benefit Plans, for more information on the rabbi trust funding requirements.

Note 6—Risk Management Activities

In July 2014, we entered into an agreement to sell IES's retail energy business. IES's risk management assets and liabilities reflected below will be included in the sale. See Note 4, Dispositions, for more information.

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

(Millions)	Balance Sheet Presentation [1]	June 30, 2014 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$9.0	$0.9
Natural gas contracts	Long-term	1.2	0.1
Financial transmission rights (FTRs) [2]	Current	5.9	0.7
Petroleum product contracts	Current	0.3	—
Coal contracts	Current	—	1.6
Coal contracts	Long-term	2.7	0.2
IES Segment			
Nonhedge derivatives			
Natural gas contracts	Current	54.8	41.3
Natural gas contracts	Long-term	24.7	13.4
Electric contracts	Current	184.6	123.4
Electric contracts	Long-term	59.7	47.4
	Current	254.6	167.9
	Long-term	88.3	61.1
Total		$342.9	$229.0

(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 $1.2 million risk management asset that was classified as held for sale at UPPCO. See Note 4, 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
IES Segment			
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 4, 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:

	June 30, 2014		
(Millions)	Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$16.3	$1.7	$14.6
IES segment	323.8	197.7	126.1
Total	340.1	199.4	140.7
Derivative assets not subject to master netting or similar arrangements	2.8		2.8
Total risk management assets	$342.9		$143.5
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$1.7	$1.7	$—
IES segment	225.4	198.3	27.1
Total	227.1	200.0	27.1
Derivative liabilities not subject to master netting or similar arrangements	1.9		1.9
Total risk management liabilities	$229.0		$29.0

	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
IES segment	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	$—
IES segment	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)	June 30, 2014	December 31, 2013
Cash collateral provided to others: [1]		
Related to contracts under master netting or similar arrangements [2]	$39.1	$ 37.6
Other	1.1	1.1
Cash collateral received from others related to contracts under master netting or similar arrangements [1]	—	0.7

(1) Cash collateral provided to others is reflected in other current assets and cash collateral received from others is reflected in other current liabilities on the balance sheets.

(2) Includes $1.3 million of cash collateral provided to others that was classified as held for sale at UPPCO at June 30, 2014, and December 31, 2013. See Note 4, Dispositions, for more information.

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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)	June 30, 2014	December 31, 2013
Utility segments	$0.6	$0.6
IES segment	44.9	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)	June 30, 2014	December 31, 2013
Collateral that would have been required:		
Utility segments	$—	$—
IES segment	173.3	197.6
Collateral already satisfied:		
IES segment — Letters of credit	4.0	4.5
Collateral remaining:		
IES segment	169.3	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:

	June 30, 2014			December 31, 2013		
(Millions)	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	2,213.0	2.0	N/A	3,124.8	29.3	N/A
FTRs (kilowatt-hours)	N/A	N/A	8,359.8	N/A	N/A	3,633.1
Petroleum products (barrels)	0.1	—	N/A	0.1	—	N/A
Coal (tons)	4.0	—	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 June 30		Six Months Ended June 30	
(Millions)	Financial Statement Presentation	2014	2013	2014	2013
Natural gas	Balance Sheet — Regulatory assets (current)	$(1.0)	$(5.6)	$(0.1)	$7.4
Natural gas	Balance Sheet — Regulatory assets (long-term)	—	(1.0)	(0.2)	(0.2)
Natural gas	Balance Sheet — Regulatory liabilities (current)	(3.4)	(5.7)	—	0.2

Natural gas	Balance Sheet — Regulatory liabilities (long-term)	0.1	(1.1)	(0.3)	(0.3)
Natural gas	Income Statement — Operating and maintenance expense	(0.1)	(0.3)	0.1	(0.1)
FTRs	Balance Sheet — Regulatory assets (current) *	(1.1)	(1.0)	(0.9)	(0.8)
FTRs	Balance Sheet — Regulatory liabilities (current) *	1.3	0.3	1.1	(0.1)
Petroleum	Balance Sheet — Regulatory assets (current)	—	(0.1)	—	(0.1)
Petroleum	Income Statement — Operating and maintenance expense	0.1	—	0.1	—
Coal	Balance Sheet — Regulatory assets (current)	(0.3)	0.8	(0.1)	2.7
Coal	Balance Sheet — Regulatory assets (long-term)	0.2	1.7	0.6	4.0
Coal	Balance Sheet — Regulatory liabilities (current)	—	(0.1)	—	(0.3)
Coal	Balance Sheet — Regulatory liabilities (long-term)	0.9	—	2.5	(2.2)

* Includes insignificant unrealized losses and gains recorded to regulatory assets and liabilities, respectively, that were classified as held for sale at UPPCO. See Note 4, Dispositions, for more information.

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IES Segment

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)	June 30, 2014 Purchases	June 30, 2014 Sales	December 31, 2013 Purchases	December 31, 2013 Sales
Commodity contracts				
Natural gas (therms)	1,164.6	1,262.5	1,199.9	1,065.4
Electric (kilowatt-hours)	40,031.9	23,508.9	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 June 30		Six Months Ended June 30	
(Millions)	Income Statement Presentation	2014	2013	2014	2013
Natural gas	Nonregulated revenue	$10.0	$33.8	$(26.9)	$37.2
Natural gas	Nonregulated cost of sales	(5.0)	(32.9)	28.0	(34.5)
Natural gas	Nonregulated revenue (reclassified from accumulated OCI) *	—	(0.1)	—	(0.2)
Electric	Nonregulated revenue	15.8	(77.6)	176.1	(13.6)
Electric	Nonregulated cost of sales	1.4	8.7	2.0	8.7
Electric	Nonregulated revenue (reclassified from accumulated OCI) *	—	(2.0)	—	(3.0)
Total		$22.2	$(70.1)	$179.2	$(5.4)

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

Note 7—Investment in ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at June 30, 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 June 30		Six Months Ended June 30	
(Millions)	2014	2013	2014	2013
Balance at the beginning of period	$517.6	$482.7	$508.4	$476.6
Add: Earnings from equity method investment	23.0	22.0	45.5	43.7
Add: Capital contributions	5.1	5.1	10.2	6.8
Less: Dividends received	18.4	17.6	36.8	34.9
Balance at the end of period	$527.3	$492.2	$527.3	$492.2

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2014	2013	2014	2013
Income statement data				

Revenues	$160.0	$152.1	$323.3	$303.9
Operating expenses	74.4	69.9	153.0	139.7
Other expense	21.9	20.9	43.5	42.4
Net income	$63.7	$61.3	$126.8	$121.8

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(Millions)	June 30, 2014	December 31, 2013
Balance sheet data		
Current assets	$80.6	$80.7
Noncurrent assets	3,612.7	3,509.5
Total assets	$3,693.3	$3,590.2
Current liabilities	$419.8	$381.5
Long-term debt	1,550.0	1,550.0
Other noncurrent liabilities	135.3	126.1
Shareholders’ equity	1,588.2	1,532.6
Total liabilities and shareholders’ equity	$3,693.3	$3,590.2

Note 8—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 June 30, 2014, we had a temporary LIFO liquidation credit of $57.9 million recorded within other current liabilities on our balance sheet. Due to seasonality requirements, PGL and NSG expect interim reductions in LIFO layers to be replenished by year end.

Note 9—Goodwill and Other Intangible Assets

The following table shows changes to our goodwill balances by segment during the six months ended June 30, 2014:

(Millions)	Natural Gas Utility	IES	Holding Company and Other	Total
Balance as of January 1, 2014				
Gross goodwill	$933.5	$6.6	$19.6	$959.7
Accumulated impairment losses	(297.6)	—	—	(297.6)
Net goodwill	635.9	6.6	19.6	662.1
Rounding adjustment	(0.1)	0.1	—	—
Goodwill impairment loss	—	(6.7)	—	(6.7)
Balance as of June 30, 2014				
Gross goodwill	933.5	6.7	19.6	959.8
Accumulated impairment losses	(297.7)	(6.7)	—	(304.4)
Net goodwill	$635.8	$—	$19.6	$655.4

In June 2014, we announced that we were in the late stages of a process to divest of IES's retail energy business. In anticipation of this divestiture, IES performed an interim goodwill impairment analysis. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss of $6.7 million in the second quarter of 2014. This goodwill impairment loss reflected the offers received for IES's retail energy business. See Note 4, Dispositions, for more information on the pending sale of IES's retail energy business.

In the second quarter of 2014, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of April 1, 2014. No impairments resulted from our annual impairment tests. As discussed above, IES recorded a goodwill impairment loss as a result of an interim test in June 2014.

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

(Millions)	June 30, 2014 Gross Carrying Amount	June 30, 2014 Accumulated Amortization	June 30, 2014 Net Carrying Amount	December 31, 2013 Gross Carrying Amount	December 31, 2013 Accumulated Amortization	December 31, 2013 Net Carrying Amount
Amortized intangible assets						
Contractual service agreements [1]	15.6	(3.0)	12.6	15.6	(1.8)	13.8
Customer-related [2]	26.8	(16.5)	10.3	26.8	(15.7)	11.1
Renewable energy credits [3]	7.2	—	7.2	8.4	—	8.4
Customer-owned equipment modifications [4]	4.0	(1.0)	3.0	4.0	(0.9)	3.1
Patents/intellectual property [5]	3.4	(0.6)	2.8	3.4	(0.5)	2.9
Compressed natural gas fueling contract assets [6]	5.6	(3.1)	2.5	5.6	(2.7)	2.9
Nonregulated easements [7]	3.7	(1.3)	2.4	3.7	(1.1)	2.6
Natural gas and electric contract assets [8]	3.9	(2.0)	1.9	3.9	(0.5)	3.4
Other	0.5	(0.3)	0.2	0.5	(0.3)	0.2
Total	$70.7	$ (27.8)	$42.9	$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	$80.9	$ (27.8)	$53.1	$82.1	$ (23.5)	$58.6

(1) 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 June 30, 2014, was approximately six years.

(2) 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 June 30, 2014, was approximately 11 years.

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

(4) 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 June 30, 2014, of approximately ten years.

(5) 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 June 30, 2014, was approximately eight years.

(6) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at June 30, 2014, was approximately seven 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 June 30, 2014, of approximately ten years.

(8) 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 June 30, 2014, was approximately three years.

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

The table below shows our amortization expense recognized in the statements of income:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2014	2013	2014	2013
Amortization recorded in nonregulated cost of sales	$1.1	$0.5	$2.1	$0.9
Amortization recorded in depreciation and amortization expense	1.1	1.2	2.2	1.7

An insignificant amount of amortization expense was recorded in discontinued operations for the six months ended June 30, 2013.

The following table shows our estimated amortization expense for the next five years, including amounts recorded through June 30, 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

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Note 10—Short-Term Debt and Lines of Credit

Our outstanding short-term borrowings were as follows:

(Millions, except percentages)	June 30, 2014	December 31, 2013
Commercial paper	$420.7	$326.0
Average interest rate on commercial paper	0.24 %	0.22 %

The commercial paper outstanding at June 30, 2014, had maturity dates ranging from July 1, 2014, through July 21, 2014.

Our average amount of commercial paper borrowings based on daily outstanding balances during the six months ended June 30, 2014, and 2013, was $215.6 million and $443.2 million, respectively.

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities:

(Millions)	Maturity	June 30, 2014	December 31, 2013
Revolving credit facility (Integrys Energy Group) [1]	05/17/2014	$—	$275.0
Revolving credit facility (Integrys Energy Group) [1]	05/17/2016	—	200.0
Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	635.0
Revolving credit facility (Integrys Energy Group)	05/08/2019	465.0	—
Revolving credit facility (WPS) [1]	05/17/2014	—	135.0
Revolving credit facility (WPS) [2]	05/07/2015	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		$1,600.0	$1,610.0
Less:			
Letters of credit issued inside credit facilities		$22.6	$52.4
Commercial paper outstanding		420.7	326.0
Available capacity under existing agreements		$1,156.7	$1,231.6

[1] These credit facilities were terminated and replaced with new credit facilities in May 2014.

[2] WPS requested approval from the PSCW to extend this facility through May 8, 2019.

Note 11—Long-Term Debt

(Millions)	June 30, 2014	December 31, 2013
WPS	$1,175.1	$1,175.1
PGL [1]	725.0	725.0
NSG	82.0	82.0
Integrys Energy Group [2]	974.8	1,074.8
Total	2,956.9	3,056.9
Unamortized discount on debt	(0.7)	(0.7)
Total debt	2,956.2	3,056.2

Less current portion	—	100.0
Total long-term debt	$2,956.2	$2,956.2

(1) PGL's $50.0 million of 2.125% Series VV Bonds were subject to a mandatory interest reset on July 1, 2014. The new interest rate on these bonds is 3.90%, and they are due in March 2030.

(1) In June 2014, our $100.0 million of 7.27% Senior Notes matured, and the outstanding principal balance was repaid.

Note 12—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 June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Effective tax rate	50.3 %	45.8 %	37.8 %	37.4 %

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

Our effective tax rate for the three months ended June 30, 2014, was higher than the federal statutory rate of 35%. In the second quarter of 2014, IES recorded a $6.7 million goodwill impairment loss. This amount is not deductible for income tax purposes.

Our effective tax rate for the three months ended June 30, 2013, was higher than the federal statutory rate of 35%. Various favorable tax adjustments were recorded in the second quarter of 2013, which when combined with a net loss for the quarter, caused the effective tax rate to increase.

During the three and six months ended June 30, 2014, there was not a significant change in our liability for unrecognized tax benefits.

Note 13—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 June 30, 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	$772.5	$91.7	$171.3	$161.8	$127.0	$76.2	$144.5
Electric utility								
Purchased power [1]	2029	907.2	42.1	54.7	42.9	53.5	56.5	657.5
Coal supply and transportation	2018	127.9	26.1	42.8	18.5	20.6	19.9	—
Nonregulated electricity and natural gas supply [2]	2020	613.7	258.9	265.4	70.6	15.0	2.7	1.1
Total		$2,421.3	$418.8	$534.2	$293.8	$216.1	$155.3	$803.1

(1) Includes minimum future commitments for UPPCO related to power purchase contracts of $14.3 million for the years 2014 to 2024. In January 2014, we announced an agreement to sell UPPCO. See Note 4, Dispositions, for more information.

(2) Represents minimum future commitments for IES. In July 2014, we entered into a definitive agreement to sell the retail energy business of IES. See Note 4, Dispositions, for more information.

We and our subsidiaries also had commitments of $1,173.0 million in the form of purchase orders issued to various vendors at June 30, 2014, that relate to normal business operations, including construction projects. Included in this amount are purchase orders issued to various vendors of UPPCO for $13.1 million and IES for $46.7 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, and
- a civil penalty of $1.2 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain Weston and Pulliam units. WPS announced that certain Weston and Pulliam units mentioned in the Consent Decree will be retired early, in June 2015. In July 2014, WPS filed for

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approval from the PSCW to reclassify the undepreciated book value of the retired units to a regulatory asset in 2015, with recovery of a full return, and for future amortization at current depreciable rates. WPS believes that it will receive approval of this treatment from the PSCW.

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.

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

In May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of June 30, 2014. It is unknown whether the Sierra Club will take further action in the future.

Columbia and Edgewater CAA Issues:
In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric and WPS. The NOV 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, 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 June 30, 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.

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

Weston Title V Air Permit:
In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, WPS challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also 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.

In May 2014, the WDNR issued an NOV to WPS alleging that WPS failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System (CEMS) certification. WPS and the WDNR have begun discussing resolution of this matter. We do not expect this matter to have a material impact on our financial statements.

In May 2014, the WDNR issued a Notice of Inquiry (NOI) to WPS alleging that WPS failed to comply with excess emission summary reporting requirements in the 2013 Weston Title V permit. WPS believes that such requirements are stayed pursuant to state law pending the outcome of the Weston Title V air permit contested case and has filed a motion with the administrative law judge requesting confirmation of the stay. Briefing is in progress, and we anticipate a decision from the administrative law judge by mid-September 2014. We do not expect this matter to have a material impact on our financial statements.

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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 from fuel combusted by a minimum of 90%, or meet certain mercury emission limits annually based on gigawatt-hours of electricity produced. 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.

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.

WPS expects to be in compliance with the State of Wisconsin's mercury rule by the end of 2014. In addition, WPS is making progress toward compliance with the MATS rule in 2015. WPS estimated capital costs of approximately $9 million for its wholly owned plants to achieve the required reductions for MATS compliance, of which approximately $3 million has been expended as of June 30, 2014. The capital costs are expected to be recovered in future rates.

Sulfur Dioxide and Nitrogen Oxide:
In July 2011, the EPA issued a final rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including WPS, challenged in the United States Court of Appeals 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 in April 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.

In June 2014, the EPA requested that the D.C. Circuit lift the stay of CSAPR. Further, the EPA asked the D.C. Circuit to change the CSAPR compliance deadlines by three years, so that Phase 1 emissions budgets would apply in 2015 and 2016, and Phase 2 emissions budgets would apply to 2017 and beyond. The stay of CSAPR is still in effect, pending the D.C. Circuit's action on the EPA's request. 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.

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 $576.1 million that we have estimated and accrued for as of June 30, 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 June 30, 2014, cash expenditures for environmental remediation not yet recovered in rates were $43.3 million. Our balance sheets include a regulatory asset of $619.4 million at June 30, 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.

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Note 14—Guarantees

The following table shows our outstanding guarantees:

	Total Amounts Committed	Expiration		
(Millions)	at June 30, 2014	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1]	$705.3	$460.5	$4.6	$240.2
Standby letters of credit [2]	27.7	27.3	0.3	0.1
Surety bonds [3]	32.7	32.7	—	—
Other guarantees [4]	55.4	1.5	—	53.9
Total guarantees [5]	$821.1	$522.0	$4.9	$294.2

(1) Consists of (a) $520.4 million, $5.0 million, and $2.0 million to support the business operations of IES, IBS, and UPPCO, respectively, and (b) $120.0 million, $57.5 million, and $0.4 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 $26.0 million issued to support IES's operations and $1.7 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 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) $6.2 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 $597.1 million of guarantees related to IES and $3.2 million of guarantees related to UPPCO. See Note 4, Dispositions, for information on the pending sale of IES's retail energy business and the pending sale of UPPCO.

Note 15—Employee Benefit Plans

Defined Benefit Plans

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

Pension Benefits	Other Postretirement Benefits

	Three Months Ended June 30		Six Months Ended June 30		Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2014	2013	2014	2013	2014	2013	2014	2013
Service cost	$5.9	$7.6	$12.5	$15.1	$4.8	$5.9	$10.7	$12.4
Interest cost	19.3	17.8	39.0	35.6	5.2	6.1	12.3	12.4
Expected return on plan assets	(28.5)	(26.1)	(57.4)	(52.7)	(7.9)	(7.6)	(16.7)	(15.3)
Loss on plan settlement	0.9	—	0.9	—	—	—	—	—
Amortization of prior service cost (credit)	0.1	1.0	0.3	2.0	(2.8)	(0.6)	(4.1)	(1.2)
Amortization of net actuarial loss	8.6	14.8	17.0	28.3	0.8	2.2	1.5	4.2
Net periodic benefit cost	$6.3	$15.1	$12.3	$28.3	$0.1	$6.0	$3.7	$12.5

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 six months ended June 30, 2014, we contributed $69.4 million to our pension plans and $0.1 million to our other postretirement benefit plans. We expect to contribute an additional $3.1 million to our pension plans and $10.9 million to our other postretirement benefit plans during the remainder of 2014, dependent upon various factors affecting us, including our liquidity position and possible tax law changes. Of the remaining contributions for 2014, contributions of $2.0 million will be funded through a transfer of assets from the rabbi trust for certain nonqualified pension plans. See the discussion below in regard to the triggering of the full funding of the rabbi trust.

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Rabbi Trust Funding Requirement

Historically, our deferred compensation programs were partially funded through shares of common stock held in a rabbi trust. The Agreement and Plan of Merger entered into with Wisconsin Energy Corporation in June 2014 triggered the potential change in control provisions in the rabbi trust agreement. These provisions required the full funding of the present value of each participant's total benefit under the deferred compensation program and certain nonqualified pension plans. As a result, $65.0 million was moved to the rabbi trust on June 30, 2014, and was recorded as restricted cash and included in other long-term assets on the balance sheet. An additional $64.8 million, consisting of cash and exchange-traded funds, was moved to the rabbi trust in July 2014. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on the merger.

Note 16—Stock-Based Compensation

In May 2014, our shareholders approved the 2014 Omnibus Incentive Compensation Plan (2014 Omnibus Plan). Under the provisions of the 2014 Omnibus Plan, the number of shares of stock that may be issued in satisfaction of plan awards may not exceed 3,000,000 shares, plus any shares forfeited under prior plans. No single employee who is our chief executive officer, chief financial officer, or any one of our other three highest compensated officers (including officers of our subsidiaries) can be granted stock options for more than 1,000,000 shares or receive a payout in excess of 250,000 shares for performance stock rights during any calendar year. Additional awards will not be issued under prior plans, although the plans continue to exist for purposes of the existing outstanding stock-based compensation awards. At June 30, 2014, stock options, performance stock rights, and restricted share units were outstanding under prior plans.

The following table reflects the stock-based compensation expense and the related deferred income tax benefit recognized in income for the three and six months ended June 30:

	Three Months Ended June		Six Months Ended June 30	
(Millions)	2014	2013	2014	2013
Stock options	$0.5	$0.5	$0.8	$0.9
Performance stock rights	9.2	1.0	9.7	3.2
Restricted share units	3.0	2.5	6.1	5.3
Nonemployee director deferred stock units	0.2	0.2	0.4	0.5
Total stock-based compensation expense	$12.9	$4.2	$17.0	$9.9
Deferred income tax benefit	$5.2	$1.7	$6.8	$4.0

No stock-based compensation cost was capitalized during the three and six months ended June 30, 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 six months ended June 30, 2014, and 2013, was $6.70 and $6.03, respectively.

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A summary of stock option activity for the six months ended June 30, 2014, and information related to outstanding and exercisable stock options at June 30, 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	(240,673)	49.32		
Outstanding at June 30, 2014	1,574,033	$ 51.90	6.6	$30.3
Exercisable at June 30, 2014	884,858	$ 49.82	5.0	$18.9

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they all exercised their options on June 30, 2014. This is calculated as the difference between our closing stock price on June 30, 2014, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the six months ended June 30, 2014, and 2013, was $4.1 million and $6.9 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $1.6 million and $2.8 million for the six months ended June 30, 2014, and 2013, respectively.

As of June 30, 2014, $2.0 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 1.9 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 one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at June 30:

	2014
Risk-free interest rate	0.06% – 0.60%
Expected dividend yield	5.28% – 5.33%
Expected volatility	17% – 23%

A summary of the activity for the six months ended June 30, 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 June 30, 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 six months ended June 30, 2014, and 2013, was $44.28 and $48.50, per performance stock right, respectively.

A summary of the activity for the six months ended June 30, 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 June 30, 2014	244,432

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of June 30, 2014, was $85.98 per performance stock right.

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No shares of common stock were distributed for performance stock rights during the six months ended June 30, 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 six months ended June 30, 2013, was $8.8 million. The actual tax benefit realized for the tax deductions from the distribution of shares during the six months ended June 30, 2013, was $3.6 million.

As of June 30, 2014, $7.6 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 1.5 years.

Restricted Share Units

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the six months ended June 30, 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	12,023	54.45
Vested and released	(204,821)	49.73
Forfeited	(3,212)	54.73
Outstanding at June 30, 2014	530,244	$ 54.46

The weighted-average grant date fair value of restricted share units awarded during the six months ended June 30, 2014, and 2013, was $55.23 and $56.01 per unit, respectively.

The total intrinsic value of restricted share unit awards vested and released during the six months ended June 30, 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 six months ended June 30, 2014, and 2013, was $4.5 million and $4.6 million, respectively.

As of June 30, 2014, $16.1 million of compensation cost related to unvested and outstanding restricted share units was expected to be recognized over a weighted-average period of 2.4 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 DSUs.

Note 17—Common Equity

We had the following changes to issued common stock during the six months ended June 30, 2014:

Balance at December 31, 2013	79,919,176
Shares issued	
Employee Stock Ownership Plan	31,764
Stock Investment Plan	12,151
Balance at June 30, 2014	79,963,091

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

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The following table reconciles common shares issued and outstanding:

	June 30, 2014		December 31, 2013	
	Shares	Average Cost *	Shares	Average Cost *
Common stock issued	79,963,091		79,919,176	
Less:				
Deferred compensation rabbi trust	433,507	$48.74	473,796	$48.50
Total common shares outstanding	79,529,584		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.

Under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we can no longer issue shares of our common stock.

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 June 30		Six Months Ended June 30	
(Millions, except per share amounts)	2014	2013	2014	2013
Numerator:				
Net income (loss) from continuing operations	$8.1	$(3.9)	$161.3	$178.3
Discontinued operations, net of tax	(0.1)	(0.8)	(0.2)	5.3
Preferred stock dividends of subsidiary	(0.8)	(0.8)	(1.6)	(1.6)
Noncontrolling interest in subsidiaries	—	0.1	0.1	0.1
Net income (loss) attributed to common shareholders	$7.2	$(5.4)	$159.6	$182.1
Denominator:				
Average shares of common stock — basic	80.2	79.4	80.2	79.0
Effect of dilutive securities				
Stock-based compensation	0.3	—	0.3	0.3
Deferred compensation	—	—	—	0.4
Average shares of common stock — diluted	80.5	79.4	80.5	79.7
Earnings (loss) per common share				
Basic	$0.09	$(0.07)	$1.99	$2.31
Diluted	0.09	(0.07)	1.98	2.29

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions)	2014	2013 *	2014	2013
Stock-based compensation	—	—	0.4	0.2
Deferred compensation	0.3	—	0.3	—

* Since we had a loss during the period, diluted earnings per share was the same as basic earnings per share, as any impacts would be anti-dilutive.

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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 June 30, 2014, these covenants restricted the payment of any dividends beyond the amount allowed under our subsidiary requirements described above.

As of June 30, 2014, total restricted net assets were $1,845.8 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $151.7 million at June 30, 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.

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

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

Capital Transactions with Subsidiaries

During the six months ended June 30, 2014, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
IBS	$ —	$ —	$ 25.0

ITF [1]	—	—	33.4
MERC	—	27.0	—
MGU	—	13.0	—
UPPCO	—	12.5	—
WPS	55.9	—	40.0
WPS Investments, LLC [2]	36.8	—	10.2
Total	$ 92.7	$ 52.5	$ 108.6

(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 June 30, 2014, we had an 86.51% ownership interest, while WPS and UPPCO had an 11.12% and 2.37% 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 18—Accumulated Other Comprehensive Loss

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

	Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
(Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at the beginning of period	$(3.7)	$(19.9)	$(23.6)	$(3.1)	$(20.1)	$(23.2)
Other comprehensive loss before reclassifications	—	—	—	—	(0.1)	(0.1)
Amounts reclassified out of accumulated other comprehensive loss	0.2	0.5	0.7	(0.4)	0.8	0.4
Net current period other comprehensive income (loss)	0.2	0.5	0.7	(0.4)	0.7	0.3
Balance at the end of period	$(3.5)	$(19.4)	$(22.9)	$(3.5)	$(19.4)	$(22.9)

	Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
(Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at the beginning of period	$(4.2)	$(35.1)	$(39.3)	$(5.2)	$(35.7)	$(40.9)
Other comprehensive income before reclassifications	0.6	—	0.6	0.7	—	0.7
Amounts reclassified out of accumulated other comprehensive loss	1.5	0.6	2.1	2.4	1.2	3.6
Net current period other comprehensive income	2.1	0.6	2.7	3.1	1.2	4.3
Balance at the end of period	$(2.1)	$(34.5)	$(36.6)	$(2.1)	$(34.5)	$(36.6)

The following table shows the reclassifications out of accumulated other comprehensive loss during the three and six months ended June 30:

	Amount Reclassified Three Months Ended June 30		Six Months Ended June 30		Affected Line Item in the Statements of Income
(Millions)	2014	2013	2014	2013	
Losses on cash flow hedges					
Utility commodity derivative contracts	$—	$—	$—	$0.2	Operating and maintenance expense (1) (2)
Nonregulated commodity derivative contracts	—	2.1	—	3.2	Nonregulated revenues (2)
Interest rate hedges	0.2	0.3	0.5	0.5	Interest expense
	0.2	2.4	0.5	3.9	Total before tax
	—	0.9	0.9	1.5	Tax expense
	0.2	1.5	(0.4)	2.4	Net of tax

Defined benefit plans

Amortization of prior service credits	—	—	(0.1)	(0.1)	[3]
Amortization of net actuarial losses	0.7	1.0	1.4	2.1	[3]
	0.7	1.0	1.3	2.0	Total before tax
	0.2	0.4	0.5	0.8	Tax expense
	0.5	0.6	0.8	1.2	Net of tax
Total reclassifications	$0.7	$2.1	$0.4	$3.6	

[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 15, Employee Benefit Plans, for more information.

Note 19—Variable Interest Entities

Unconsolidated Variable Interest Entities

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. This joint venture was established to own and operate compressed natural gas fueling stations. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. At December 31, 2013, ITF was the primary beneficiary of this variable interest entity, and, as a result, we consolidated the assets, liabilities, and statements of income of the joint venture. However, in April 2014, ITF and AMP Americas LLC restructured this joint venture. Due to 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. At June 30, 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 also not significant.

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 June 30, 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 June 30, 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. In January 2014, we announced an agreement to sell UPPCO. See Note 4, Dispositions, for more information on the pending sale of UPPCO.

Note 20—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.

In July 2014, we entered into an agreement to sell IES's retail energy business. IES's risk management assets and liabilities reflected below will be included in the sale. See Note 4, Dispositions, for more information. The following tables show assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	June 30, 2014			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$1.1	$9.1	$—	$10.2
Financial transmission rights (FTRs)	—	—	5.9	5.9
Petroleum product contracts	0.3	—	—	0.3
Coal contracts	—	—	2.7	2.7
IES Segment				
Natural gas contracts	20.6	29.0	29.9	79.5
Electric contracts	98.6	126.2	19.5	244.3
Total Risk Management Assets	$120.6	$164.3	$58.0	$342.9
Investment in exchange-traded funds	$16.8	$—	$—	$16.8
Liabilities				
Risk Management Liabilities				