INTEGRYS ENERGY GROUP, INC.
Form 10-K
February 27, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549
FORM 10-K
(Mark One)

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

For the fiscal year ended December 31, 2013
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) 130 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $1 par value	New York Stock Exchange
6.00% Junior Subordinated Notes due 2073	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]

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 [ ]

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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 (§232.405 of this chapter) 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]
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]

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.

$4,623,528,068 as of June 28, 2013

Number of shares outstanding of each class of common stock, as of February 25, 2014

Common Stock, $1 par value, 79,963,091 shares

DOCUMENT INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Integrys Energy Group, Inc. Annual Meeting of Shareholders to be held on May 15, 2014 are incorporated by reference into Part III.

INTEGRYS ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2013

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Acronyms Used in this Annual Report on Form 10-K

AFUDC	Allowance for Funds Used During Construction
AMRP	Accelerated Natural Gas Main Replacement Program
ASC	Accounting Standards Codification
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC
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
WRPC	Wisconsin River Power Company

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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 this Annual Report on Form 10-K for the year ended December 31, 2013, and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- The ability to retain market-based rate authority;
- The effects, extent, and timing of competition or additional regulation in the markets in which our subsidiaries operate;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries’ liquidity and financing efforts;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries’ counterparties, affiliates, and customers to meet their obligations;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer energy use, customer growth, and our ability to adequately forecast energy use for our customers;
- The ability to use tax credit and loss carryforwards;
- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;
- The risk associated with the value of goodwill or other intangible assets and their possible impairment;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed timely or within budgets;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
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- 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

ITEM 1. BUSINESS

A. GENERAL

In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Energy Group, Inc. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, including financial and geographic information about each reportable business segment, see Note 27, Segments of Business, and Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations.

Integrys Energy Group, Inc.

We are a diversified energy holding company headquartered in Chicago, Illinois. We were incorporated in Wisconsin in 1993. Our wholly owned subsidiaries provide products and services in both the regulated and nonregulated energy markets. In addition, we have a 34% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). We have five reportable segments, which we discuss below.

Facilities

For information regarding our facilities, see Item 2 - Properties. For our utility and nonregulated plant asset book value, see Note 5, Property, Plant, and Equipment.

Available Information

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, registration statements, and any amendments to these documents are available, free of charge, on our website, www.integrysgroup.com, as soon as reasonably practicable after they are filed with or furnished to the SEC. Reports, statements, and amendments posted on our website do not include access to exhibits and supplemental schedules electronically filed with the reports, statements, or amendments. We are not including the information contained on or available through our website as a part of, or incorporating such information by reference into, this Annual Report on Form 10-K.

You may obtain materials we filed with or furnished to the SEC at the SEC Public Reference Room at 100 F Street, NE, Washington, DC 20549. To obtain information on the operation of the Public Reference Room, you may call the SEC at 1-800-SEC-0330. You may also view our reports, proxy and registration statements, and other information (including exhibits) filed or furnished electronically with the SEC, at the SEC's website at www.sec.gov.

B. REGULATED NATURAL GAS UTILITY OPERATIONS

Our natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS. MERC and MGU, both Delaware corporations, began operations in July 2006 and April 2006, respectively, when we acquired their existing natural gas distribution operations in Minnesota and Michigan. NSG and PGL, both Illinois corporations, began operations in 1900 and 1855, respectively. We acquired NSG and PGL in February 2007 in the PELLC merger. WPS, a Wisconsin corporation, began operations in 1883.

Our regulated natural gas utilities provide service to approximately 1,698,000 residential, commercial and industrial, transportation, and other customers. Our customers are located in Chicago and the northern suburbs of Chicago, northeastern Wisconsin and an adjacent portion of Michigan's Upper Peninsula, various cities and communities throughout Minnesota, and the southern portion of lower Michigan.

Natural Gas Supply

Our regulated natural gas utilities manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns at the lowest reasonable cost.

Our regulated natural gas supply requirements are met through a combination of fixed price purchases, index price purchases, contracted and owned storage, peak-shaving facilities, and natural gas supply call options. Our regulated natural gas subsidiaries contract for fixed-term firm natural gas supply each year (in the United States and Canada) to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, our regulated natural gas utilities purchase additional natural gas supply on the monthly and daily spot markets.

For more information on our regulated natural gas utility supply and transportation contracts, see Note 15, Commitments and Contingencies.

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Our regulated natural gas utilities own two storage fields and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, thus providing a hedge against supply cost volatility. Our regulated natural gas utilities contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our regulated natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our regulated natural gas utilities when negotiating new agreements for transportation and storage services. Our regulated natural gas utilities further reduce their supply cost volatility through the use of financial instruments such as commodity futures, swaps, and options as part of their hedging programs.

PGL owns and operates an underground natural gas storage reservoir in central Illinois (Manlove Field) and a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in PGL's regulatory rate base. PGL also uses a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to its wholesale customers. Customers deliver natural gas to PGL for storage through an injection into the storage reservoir, and PGL returns the natural gas to the customers under an agreed schedule through a withdrawal from the storage reservoir. Title to the natural gas does not transfer to PGL. Therefore, all natural gas related only to the hub remains customer-owned. PGL recognizes service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

The table below is a rollforward of PGL's natural gas in storage balances related to the natural gas hub as well as natural gas hub service fees collected from wholesale customers:

Thousands of Dekatherms (MDth)	2013	2012	2011
Beginning Balance, January 1	5,240	5,261	5,156
Injections	7,000	7,000	7,000
Withdrawals	(7,097)	(7,021)	(6,895)
Ending Balance, December 31	5,143	5,240	5,261

(Millions)	2013	2012	2011
Natural gas hub service fees	$4.3	$3.9	$5.4

Our regulated natural gas utilities had adequate capacity to meet all firm natural gas demand obligations during 2013 and expect to have adequate capacity to meet all firm demand obligations during 2014. Our regulated natural gas utilities' forecasted design peak-day throughput is 3,857 MDth for the 2013 through 2014 heating season.

The sources of our deliveries to customers (including transportation customers) for regulated natural gas utility operations were as follows:

(MDth)	2013	2012	2011
Natural gas purchases	232,007	184,188	217,288
Natural gas purchases for electric generation	2,246	2,215	1,780
Customer-owned natural gas received	191,101	176,598	181,021
Underground storage, net	6,123	2,749	(1,425)
Hub fuel in kind *	179	179	180
Liquefied petroleum gas (propane)	1	1	1
Owned storage cushion injection	(1,097)	(1,097)	(1,098)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted-for natural gas	(12,992)	(8,037)	(10,809)

Total	417,568	356,796	386,938

* This delivered natural gas was originally provided by hub customers whose contract requires them to provide additional natural gas to compensate for unaccounted-for natural gas in future deliveries.

Regulatory Matters

Our regulated natural gas utility retail rates are regulated by the ICC, MPSC, MPUC, and PSCW. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Sales are made and services are rendered by the regulated natural gas utilities pursuant to rate schedules on file with the respective commissions. These rate schedules contain various service classifications, which largely reflect customers' different uses and levels of consumption. Our regulated natural gas utilities bill customers for the distribution of natural gas as well as for a natural gas charge representing third-party costs for purchasing, transporting, and storing natural gas. This charge also includes gains, losses, and costs incurred under hedging programs, the amount of which is also subject to applicable commission authority. Prudently incurred natural gas costs are passed through to customers in current rates and,

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therefore, have no impact on margins. Commissions in respective jurisdictions conduct annual proceedings regarding the reconciliation of revenues from the natural gas charge and related natural gas costs.

Almost all of the natural gas our regulated natural gas utilities distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services, including PGL's natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the state commissions are responsible for monitoring our regulated natural gas utilities' safety compliance programs for our pipelines under United States Department of Transportation regulations. These regulations include 49 Code of Federal Regulations (CFR) Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

All of our regulated natural gas utility subsidiaries are required to provide service and grant credit (with applicable deposit requirements) to customers within their service territories. Our regulated natural gas utilities are generally not allowed to discontinue service during winter moratorium months to residential customers who do not pay their bills. The Federal and certain state governments have programs that provide for a limited amount of funding for assistance to low-income customers of the utilities.

See Note 26, Regulatory Environment, for information regarding rate cases, decoupling mechanisms, bad debt recovery mechanisms, and other cost recovery mechanisms at our regulated natural gas utilities.

Other Matters

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. During 2013, the regulated natural gas utility segment recorded approximately 64% of its revenues in January, February, March, November, and December.

Competition

Although our natural gas retail rates are regulated by various commissions, the regulated natural gas utilities still face varying degrees of competition from other entities and other forms of energy available to consumers. Many large commercial and industrial customers have the ability to switch between natural gas and alternate fuels. Due to the volatility of energy commodity prices, our regulated natural gas utilities have seen customers with dual fuel capability switch to alternate fuels for short periods of time, then switch back to natural gas as market rates change.

Our regulated natural gas utilities all offer natural gas transportation service, and certain of our regulated natural gas utilities also offer interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our regulated natural gas utilities' distribution systems to transport the natural gas to their facilities. Our regulated natural gas utilities still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has no impact on our regulated natural gas utility segment net income, as it is offset by an equal reduction to natural gas costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Working Capital Requirements

The working capital needs of our regulated natural gas utility operations vary significantly over time due to volatility in levels of natural gas inventories and the price of natural gas. Our regulated natural gas utilities' working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our regulated natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

C. REGULATED ELECTRIC UTILITY OPERATIONS

The electric utility segment includes the regulated electric utility operations of WPS and UPPCO. WPS, a Wisconsin corporation, began operations in 1883. UPPCO, a Michigan corporation, began operations in 1884. We acquired UPPCO in September 1998. In January 2014, we announced an agreement to sell UPPCO. The transaction is expected to close later in 2014. See Note 29, Subsequent Event, for more information.

The regulated electric utility operations of WPS and UPPCO provide service to approximately 497,000 residential, commercial and industrial, wholesale, and other customers. WPS's customers are located in northeastern Wisconsin and an adjacent portion of Michigan's Upper Peninsula. UPPCO's customers are located in Michigan's Upper Peninsula. Wholesale electric service is provided to various WPS customers, including municipal utilities, electric cooperatives, energy marketers, other investor-owned utilities, and municipal joint action agencies. UPPCO no longer provides

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power supply service to wholesale electric customers due to the expiration of its remaining wholesale electric contracts in 2011. In 2013, retail electric revenues accounted for 89.0% of total electric revenues, while wholesale electric revenues accounted for 11.0% of total electric revenues.

In 2013, WPS reached a firm peak demand of 2,299 megawatts on July 18. At the time of this peak, WPS's total firm resources (i.e., generation plus firm purchases) totaled 3,213 megawatts.

The PSCW requires WPS to maintain a planning reserve margin above its projected annual peak demand forecast to help ensure reliability of electric service to its customers. The PSCW has a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO under Module E of its Open Access Transmission and Energy Markets Tariff. MISO has a 14.2% reserve margin requirement from January 1 through May 31, 2014, and 14.8% for the remainder of 2014. The MPSC does not have minimum guidelines for future supply reserves.

In 2013, UPPCO reached a firm peak demand of 101 megawatts on August 20. At the time of this peak, UPPCO's total firm resources totaled 131 megawatts. The MPSC does not have minimum guidelines for future supply reserves; however, the MISO short-term planning reserve margin requirements described above also apply to UPPCO.

WPS and UPPCO expect future supply reserves to meet the minimum planning reserve margin requirements for 2014. WPS and UPPCO had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2013 and expect to have adequate capacity to meet all obligations during 2014.

Electric Supply

Both WPS and UPPCO are members of MISO, a FERC-approved, independent, nonprofit organization, which operates a financial and physical electric wholesale market in the Midwest. WPS and UPPCO offer their generation and bid their customer load into the MISO market. MISO evaluates WPS's, UPPCO's, and other market participants' energy offers into, and subsequent withdrawals from, the system to economically dispatch electricity within the system. MISO settles the participants' offers and bids based on locational marginal prices, which are market-driven values based on the specific time and location of the purchase and/or sale of energy.

Electric Generation and Supply Mix

The sources of our electric utility supply were as follows:

(Millions) Energy Source (kilowatt-hours)	2013	2012	2011
Company-owned generation units			
Coal	8,723.1	7,390.1	8,634.5
Natural gas, fuel oil, and tire-derived fuel	1,539.6	176.1	135.8
Wind	309.7	330.6	309.3
Hydro	307.1	251.2	348.9
Total company-owned generation units	10,879.5	8,148.0	9,428.5
Power purchase contracts			
Nuclear (Kewaunee Power Station) (1)	2,808.3	2,655.5	2,674.4
Hydro	553.8	392.6	570.7
Natural gas (Fox Energy Center, LLC (2) and Combined Locks Energy Center, LLC (3))	395.1	2,892.6	1,593.9

Wind	209.1	220.1	210.6
Other	674.0	1,580.5	235.8
Total power purchase contracts	4,640.3	7,741.3	5,285.4
Purchased power from MISO	863.9	849.3	1,605.2
Purchased power from other	107.3	106.3	100.1
Total purchased power	5,611.5	8,696.9	6,990.7
Opportunity sales			
Sales to MISO	(1,592.0)	(1,800.6)	(1,242.0)
Net sales to other	(407.8)	(128.4)	(64.6)
Total opportunity sales	(1,999.8)	(1,929.0)	(1,306.6)
Total electric utility supply	14,491.2	14,915.9	15,112.6

(1) This power purchase contract expired in December 2013.

(2) This power purchase contract was terminated in connection with the purchase of Fox Energy Company LLC in March 2013. See Note 3, Acquisitions, for more information.

(3) This power purchase contract expired in October 2011.

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Fuel Costs

The cost of fuel per generation of one million British thermal units was as follows:

Fuel Type	2013	2012	2011
Coal	$2.57	$2.52	$2.44
Natural gas	3.47	3.97	5.64
Fuel oil	21.78	26.12	21.24

Coal Supply

Coal is the primary fuel source for WPS's electric generation facilities. WPS's regulated fuel portfolio strategy is to maintain a 35- to 45-day supply of coal at each plant site. The majority of the coal is purchased from Powder River Basin mines located in Wyoming. This low sulfur coal has been WPS's lowest cost coal source of any of the subbituminous coal-producing regions in the United States. Historically, WPS has purchased coal directly from the producer for its wholly owned plants. WPS also purchases the coal for the jointly owned Weston 4 plant, and Dairyland Power Cooperative reimburses WPS for its share of the coal costs. Wisconsin Power and Light Company purchases coal for the jointly owned Edgewater and Columbia plants and is reimbursed by WPS for its share of the coal costs. At December 31, 2013, WPS had coal transportation contracts in place for 100% of its 2014 coal transportation requirements. See Note 15, Commitments and Contingencies, for more information on coal purchases and coal deliveries under contract.

Power Purchase Agreements

Our electric utilities enter into short-term and long-term power purchase agreements to meet a portion of their electric energy supply needs. See Note 15, Commitments and Contingencies, for more information on power purchase obligations.

Regulatory Matters

WPS's retail electric rates are regulated by the PSCW and the MPSC. UPPCO's retail electric rates are regulated by the MPSC. The FERC regulates wholesale electric rates for WPS and UPPCO. WPS and UPPCO must also comply with mandatory electric system reliability standards developed by the North American Electric Reliability Corporation (NERC), the electric reliability organization certified by the FERC. The Midwest Reliability Organization is responsible for the enforcement of NERC’s standards for WPS and UPPCO.

The PSCW sets rates through its ratemaking process, which is based on recovery of operating costs and a return on invested capital. One of the cost recovery components is fuel and purchased power, which is governed by a fuel window mechanism. See Note 1(e), Revenue and Customer Receivables, for more information. The MPSC's ratemaking process is similar to the PSCW's, with the exception of fuel and purchased power costs, which are recovered on a one-for-one basis. WPS has formula-based rates, as approved by the FERC, for the sale of electricity to its wholesale customers.

See Note 26, Regulatory Environment, for more information regarding the rate cases and decoupling mechanisms of our electric utilities.

Hydroelectric Licenses

WPS, UPPCO, and WRPC (a company in which WPS has 50% ownership) have long-term licenses from the FERC for their hydroelectric facilities.

Other Matters

Seasonality

Our electric utility sales in Wisconsin are generally higher during the summer months due to the air conditioning requirements of customers. Our regulated electric utility sales in Michigan do not follow a significant seasonal trend due to cooler climate conditions in the Upper Peninsula of Michigan.

Competition

The retail electric utility market in Wisconsin is regulated by the PSCW. Retail electric customers currently do not have the ability to choose their electric supplier. However, utilities still face competition from other energy sources, such as self-generation by large industrial customers and alternative energy sources. In addition, utilities work to attract new customers into their service territories in order to increase sales. As a result, there is competition among utilities to keep energy rates low. Wisconsin utilities have continued to refine regulated tariffs in order to pass on the true cost of electricity to each class of customer by reducing or eliminating rate subsidies among different ratepayer classes.

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Michigan electric energy markets are open to competition, subject to certain limitations. During 2012 and 2013, alternate energy suppliers entered our service territories in the Upper Peninsula of Michigan, creating an active competitive market.

D. INTEGRYS ENERGY SERVICES

Integrys Energy Services, Inc., a Wisconsin corporation, was established in 1994. Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes, primarily distributed solar assets.

Integrys Energy Services and its subsidiaries market electricity and natural gas in various retail markets, serving commercial and industrial customers, as well as direct and aggregated small commercial and residential customers. Aggregated customers are municipalities, associations, or groups of customers that have joined together to negotiate the purchase of electricity or natural gas as a larger group. At December 31, 2013, Integrys Energy Services was serving aggregated customers in Illinois, Ohio, and Michigan.

Integrys Energy Services invests in and promotes renewable energy, primarily distributed solar, which it believes is important to the future of the energy industry. Clean, renewable, and efficient energy sources are developed, acquired, owned, and operated by Integrys Energy Services. Integrys Energy Services assists customers with selecting an energy solution that meets their needs and collaborates with developers of energy projects to overcome challenges with integrating the technical, regulatory, and financial aspects of their projects.

Integrys Energy Services invested in a joint venture with Duke Energy Generation Services to build and finance distributed solar projects throughout the United States. While there is no current commitment to invest in new solar projects through this joint venture, Duke Energy Generation Services and Integrys Energy Services are continuing to pursue projects that meet acceptable return requirements and intend to equally fund the necessary equity capital for construction and ownership of future solar projects.

Integrys Energy Services uses physical and financial derivative instruments, including forwards, futures, options, and swaps, to manage its exposure to market risks from its energy assets and energy supply portfolios in accordance with limits and approvals established in its risk management and credit policies.

As previously discussed, Integrys Energy Services' long-term energy asset strategy is to invest in distributed renewable projects. Consistent with this strategy, Integrys Energy Services is currently pursuing the sale of Combined Locks Energy Center, a natural gas-fired cogeneration facility located in Wisconsin. In March 2013, WPS Empire State, Inc., a subsidiary of Integrys Energy Services, sold all of the membership interests of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC, both of which owned natural gas-fired generation plants located in the state of New York. In addition, in November 2012, Sunbury Holdings, LLC, a subsidiary of Integrys Energy Services, sold all of the membership interests of WPS Westwood Generation, LLC, a waste coal generation plant located in Pennsylvania. For more information, see Note 4, Discontinued Operations.

Energy Supply

Physical supply obligations are created when Integrys Energy Services executes forward retail customer sales contracts. Integrys Energy Services' electricity supply requirements are primarily met through bilateral electricity purchase agreements with generation companies and other marketers, as well as purchases from regional power pools. Integrys Energy Services does not own natural gas reserves, so all natural gas supply is procured from producers and other suppliers in the wholesale market. Natural gas is sourced at the customer demand regions, or from the supply region and transported to the customer demand regions under natural gas transportation contracts.

Fuel Supply for Generation Facilities

Integrys Energy Services' natural gas-fired facility (51.5% of its installed generation portfolio) is subject to market price volatility and is dispatched to produce energy only when it is economical to do so. This facility was classified as held for sale. See Note 4, Discontinued Operations, for more information regarding this held for sale facility. Integrys Energy Services' renewable energy facilities (48.5% of its installed generation portfolio) are powered by renewable resources such as solar irradiance or landfill gas. There is no market price risk associated with the fuel supply of these facilities; however, production at these facilities can be intermittent due to the availability of the renewable energy resource.

Regulatory Matters

Integrys Energy Services is a FERC-authorized power marketer and has all of the licenses required to conduct business in the states in which it operates.

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Other Matters

Customer Segmentation

As of December 31, 2013, Integrys Energy Services' largest retail electric markets included Illinois, New York, New England, Michigan, Mid-Atlantic, and Ohio. In addition, Integrys Energy Services' largest retail natural gas markets included Wisconsin, Mid-Atlantic, Illinois, Michigan, and Ohio. Integrys Energy Services continuously reviews and evaluates the profitability of its operations in each of its markets. Integrys Energy Services continues to concentrate on adding customers in existing markets and placing emphasis on business that provides an appropriate rate of return. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - Introduction for a discussion of the current strategy for Integrys Energy Services.

Integrys Energy Services is not dependent on any one customer segment. Rather, a significant percentage of its retail sales volume is derived from residential customers and several industries, including educational services; paper and allied products; food and kindred products; executive, legislative, and general government; real estate; and health services.

Seasonality

Integrys Energy Services’ business, in the aggregate, is somewhat seasonal with certain products selling more heavily in certain seasons than in others. Sales of natural gas generally peak in the winter months, while sales of electricity generally peak in the summer months. The first and fourth quarters, in the aggregate, have typically been the most profitable periods. Integrys Energy Services' business can be volatile as a result of market conditions and the related market opportunities available to its customers.

Competition

Integrys Energy Services is a nonregulated retail energy marketer that competes against regulated utilities and other retail energy marketers on the basis of price, reliability, customer service, product offerings, financial strength, consumer convenience, performance, and reputation.

The competitive landscape differs in each regional area and within each targeted customer segment. For residential and small commercial customers, the primary competitive challenges come from the incumbent utility (provider of default service), established national marketers, regional marketers, and affiliated utility marketing companies. The large commercial, institutional, and industrial segments are very competitive in most markets with nearly all natural gas customers having already switched away from utility supply to a competitive retail energy provider. National affiliated marketers, energy producers, and other independent retail energy companies compete for customers in this segment.

The local utilities generally have the advantage of long-standing relationships with their customers, and they have longer operating histories, greater financial and other resources, and greater name recognition in their markets compared to Integrys Energy Services. In addition, local utilities have been subject to many years of regulatory oversight and, thus, have a significant amount of experience regarding the policy preferences of their regulators. Local utilities may seek to decrease their tariff retail rates to limit or preclude opportunities for competitive energy suppliers and may seek to establish rates, terms, and conditions to the disadvantage of competitive energy suppliers.

The retail electric and natural gas markets in which Integrys Energy Services operates continue to evolve. Integrys Energy Services has been able to take advantage of continued growth opportunities as evidenced by increasing volumes delivered and contracted for future delivery in certain markets. During 2013, delivered electric and natural gas volumes grew approximately 60% and 58%, respectively, compared with 2012. In addition, Integrys Energy Services' electric and natural gas volumes for future delivery grew by approximately 3% and 102%, respectively, from December 31, 2012 to December 31, 2013. The low growth in electric volumes for future delivery is primarily due to being selected as the electric supplier for the City of Chicago aggregation program in December 2012. Although this contract extends through May 2015, the City of Chicago initially committed volumes through only May 2014. As of December 31, 2013, the City of Chicago had not yet committed volumes for the remaining term of the contract. Despite continued growth, sustained low commodity prices, capital costs, and market volatility have led to continued competitive pressure on per-unit margins.

Working Capital

The working capital needs of Integrys Energy Services vary significantly over time due to volatility in commodity prices and related collateral calls, and levels of natural gas storage inventories. Integrys Energy Services' working capital needs are met by cash generated from operations, equity infusions, and short-term debt. As of December 31, 2013, Integrys Energy Services had the ability to borrow up to $665.0 million through an intercompany credit facility with us. As of December 31, 2013, we had provided total parental guarantees of $541.5 million on behalf of Integrys Energy Services, which includes guarantees for the current retail business as well as residual guarantees related to exited businesses. Our exposure under these guarantees related to open transactions at December 31, 2013, was $296.2 million.

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E. ELECTRIC TRANSMISSION INVESTMENT

The electric transmission investment segment consists of our approximate 34% ownership interest in ATC. ATC, which began operations in 2001, owns and operates the electric transmission system, under the direction of the MISO, in parts of Wisconsin, Illinois, Minnesota and the Upper Peninsula of Michigan. ATC is subject to regulation by FERC as to rates, terms of service, and financing and by state regulatory commissions as to other aspects of business, including the construction of electric transmission assets. See Note 8, Equity Method Investments, for more information about ATC.

F. HOLDING COMPANY AND OTHER SEGMENT

The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS. The compressed natural gas operations of ITF are included in this segment as of September 1, 2011, the date on which we acquired Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle). See Note 3, Acquisitions, for more information about the acquisition of Trillium and Pinnacle.

G. ENVIRONMENTAL MATTERS

See Note 15, Commitments and Contingencies, for more information on our environmental matters.

H. CAPITAL REQUIREMENTS

For information on our capital requirements, see Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources.

I. EMPLOYEES

At December 31, 2013, our consolidated subsidiaries had the following full-time employees:

	Total Number of Employees	Percentage of Employees Covered by Collective Bargaining Agreements	
PGL	1,296	74	%
IBS	1,288	—	%
WPS	1,242	69	%
Integrys Energy Services	294	—	%
MERC	217	20	%
NSG	166	77	%
MGU	159	69	%
UPPCO	118	81	%
ITF	108	—	%
Total	4,888	45	%

Our subsidiaries have collective bargaining agreements with various unions which are summarized in the table below.

Union	Subsidiary	Contract Expiration Date
Local 510 of the International Brotherhood of Electrical Workers, AFL CIO	UPPCO	April 12, 2014

Local 12295 of the United Steelworkers of America, AFL CIO CLC	MGU	January 15, 2015
Local 417 of the Utility Workers Union of America, AFL CIO	MGU	February 15, 2016
Local 31 of the International Brotherhood of Electrical Workers, AFL CIO	MERC	May 31, 2016
Local 420 of the International Union of Operating Engineers	WPS	October 16, 2016
Local 18007 of the Utility Workers Union of America	PGL	April 30, 2018
Local 2285 of the International Brotherhood of Electrical Workers, AFL CIO	NSG	June 30, 2019

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J. EXECUTIVE OFFICERS OF INTEGRYS ENERGY GROUP

Name and Age [1]		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	60	Chairman and Chief Executive Officer	01-01-14
		Chairman, President and Chief Executive Officer	04-01-10
		President and Chief Executive Officer	01-01-09
Lawrence T. Borgard	52	President and Chief Operating Officer	01-01-14
		President and Chief Operating Officer – Utilities	04-05-09
		President and Chief Operating Officer – Integrys Gas Group [2]	02-21-07
Phillip M. Mikulsky	65	Executive Vice President – Corporate Initiatives and Chief Security Officer	01-01-13
		Executive Vice President – Business Performance and Shared Services	12-26-10
		Executive Vice President – Corporate Development and Shared Services	09-21-08
Mark A. Radtke	52	Executive Vice President – Shared Services and Chief Strategy Officer	01-01-13
		Executive Vice President and Chief Strategy Officer	12-26-10
		Chief Executive Officer – Integrys Energy Services	01-10-10
		President and Chief Executive Officer – Integrys Energy Services	06-01-08
James F. Schott	56	Vice President and Chief Financial Officer	01-01-13
		Vice President – External Affairs	03-22-10
		Vice President – Regulatory Affairs	07-18-04
Linda M. Kallas	54	Vice President and Controller	05-16-13
		Vice President and Corporate Controller	09-01-12
		Vice President of Finance and Accounting Services	06-06-07
William J. Guc	44	Vice President and Treasurer	12-01-10
		Vice President – Finance and Accounting and Controller – Integrys Energy Services	03-07-10
		Vice President and Controller – Integrys Energy Services	09-21-08
William D. Laakso	51	Vice President – Human Resources and Corporate Communications	01-01-13
		Vice President – Human Resources	09-21-08
Jodi J. Caro	48	Vice President, General Counsel and Secretary	11-09-12
		Vice President, General Counsel and Assistant Secretary	02-19-12
		Vice President of Legal Services	01-07-08
Daniel J. Verbanac	50	President – Integrys Energy Services	01-01-10
		Chief Operating Officer – Integrys Energy Services (previously named WPS Energy Services)	02-15-04

(1) Officers and their ages are as of January 1, 2014. None of the executives listed above are related by blood, marriage, or adoption to any of our other officers listed or to any of our directors. Each officer holds office until his or her successor has been duly elected and qualified, or until his or her death, resignation, disqualification, or removal.

(2) The Integrys Gas Group included MGU, MERC, NSG, and PGL.

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ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors, as well as the other information included or incorporated by reference in this Annual Report on Form 10-K, when making an investment decision.

We are subject to government regulation, which may have a negative impact on our businesses, financial position, and results of operations.

We are subject to comprehensive regulation by several federal and state regulatory agencies and local governmental bodies. This regulation significantly influences our operating environment and may affect our ability to recover costs from regulated utility customers. Many aspects of our operations are regulated, including, but not limited to, construction and operation of facilities, conditions of service, the issuance of securities, and the rates that we can charge customers. We are required to have numerous permits, approvals, and certificates from these agencies to operate our business. Failure to comply with any applicable rules or regulations may lead to penalties or customer refunds, which could have a material adverse impact on our financial results.

Existing statutes and regulations may be revised or reinterpreted by federal and state regulatory agencies, or these agencies may adopt new laws and regulations that apply to us. We are unable to predict the impact on our business and operating results of any such actions by these agencies. However, changes in regulations or the imposition of additional regulations may require us to incur additional expenses or change business operations, which may have an adverse impact on our results of operations.

The rates, including adjustments determined under riders, that our regulated utilities are allowed to charge for retail and wholesale services are the most important factors influencing our business, financial position, results of operations, and liquidity. Rate regulation is premised on providing an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, there is no assurance that regulatory commissions will consider all the costs of our regulated utilities to have been prudently incurred. In addition, the regulatory process will not always result in rates that will produce full recovery of such costs or provide for a reasonable return on equity. Certain expense and revenue items are deferred as regulatory assets and liabilities for future recovery or refund to customers, as authorized by regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for prudence and reasonableness. If recovery of costs is not approved or is no longer deemed probable, regulatory assets would be recognized in current period expense and could have a material adverse impact on our financial results.

Our operations are subject to risks beyond our control, including but not limited to, cyber security attacks, terrorist attacks, acts of war, or unauthorized access to personally identifiable information.

Any future terrorist attack, cyber security attack, and/or act of war affecting our facilities and operations could have an adverse impact on our results of operations, financial condition, and cash flows. The energy industry uses sophisticated information technology systems and network infrastructure, which control an interconnected system of generation, distribution, and transmission systems shared with other third parties. A successful physical or cyber security attack may occur despite our security measures or those that we require our vendors to take, which include compliance with reliability standards and critical infrastructure protection standards. Successful physical and cyber security attacks, including those targeting information systems and electronic control systems used at generating facilities and electric and natural gas transmission, distribution, and storage systems, could severely disrupt our operations and result in loss of service to customers. The risk of such attacks may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our business requires the collection and retention of personally identifiable information of our customers, shareholders, and employees, who expect that we will adequately protect such information. A significant theft, loss, or fraudulent use of personally identifiable information may cause our business reputation to be adversely impacted, may lead to potentially large costs to notify and protect the impacted persons, and/or may cause us to become subject to legal claims, fines, or penalties, any of which could adversely impact our results of operations.

The costs of repairing damage to our facilities, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

We are subject to environmental laws and regulations, compliance with which could be difficult and costly.

We are subject to numerous federal and state environmental laws and regulations that affect many aspects of our operations, including future operations. These laws and regulations relate to air emissions, water quality, wastewater discharges, hazardous materials management, and the generation, transport, and disposal of solid and hazardous wastes. Such laws and regulations require us to implement compliance processes and obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections, and other approvals. Existing laws and regulations may be revised and/or new laws and regulations passed, including, but not limited to, rules addressing greenhouse gases such as carbon dioxide and methane, mercury, sulfur dioxide, and nitrogen oxide emissions, and the management of coal combustion byproducts, including fly ash.

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The EPA began regulating greenhouse gas emissions under the Clean Air Act (CAA) by applying the Best Available Control Technology (BACT) requirements, which are associated with the New Source Review Program. These requirements apply to new and modified larger greenhouse gas emitters. In September 2013, the EPA reproposed rules that impose carbon dioxide emission rate limits on new electric generating units and is expected to finalize such rules in a timely manner. The EPA is also expected to propose rules for existing units by no later than June 1, 2014, and issue final rules by June 1, 2015, with state implementation plans due by June 30, 2016. Until legislation is passed at the federal or state level or the EPA adopts final rules for electric utility steam generating units, it remains unclear as to (1) which industry sectors will be impacted, (2) when compliance will be required, (3) the magnitude of the greenhouse gas emissions reductions that will be required, and (4) the costs and opportunities associated with compliance.

It is possible that future carbon legislation and greenhouse gas emission regulations will increase the cost of electricity produced at fossil fuel-fired generation units. Future regulation may also affect the capital expenditures we would make for our generation units or distribution systems, including costs to further limit the greenhouse gas emissions from our operations through control technology such as carbon capture and storage. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could also affect the availability or cost of fossil fuels. The steps we could be required to take to ensure that our facilities are in compliance with any such laws and regulations could be prohibitively expensive. As a result, certain coal-fired electric generating facilities may become uneconomical to run and could result in early retirement of some of our units or may force us to convert the units to an alternative type of fuel.

Our natural gas delivery systems may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair of natural gas delivery systems. Fugitive gas typically vents to the atmosphere and consists primarily of methane. Carbon dioxide is also a byproduct of natural gas consumption. As a result, future legislation to regulate greenhouse gas emissions could increase the price of natural gas, restrict the use of natural gas, adversely affect our ability to operate our natural gas facilities, and/or reduce natural gas demand.

Environmental laws and regulations can also require us to incur expenditures for cleanup costs, damages arising from contaminated properties, and monitoring obligations. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all recoverable costs incurred to date, management's best estimates of future costs for investigation and remediation, and legal expenses, and are net of amounts recovered by or that may be recovered from insurance or other entities. The ultimate costs to remediate these sites could vary from the amounts currently accrued.

There is uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Citizen groups that feel environmental regulations are not being sufficiently enforced by environmental regulatory agencies may also bring citizen enforcement actions against us. Such actions could seek penalties, injunctive relief, and costs of litigation. There is also a risk that private citizens may bring lawsuits to recover environmental damages they believe they have incurred.

Compliance with current and future environmental laws and regulations may result in increased capital, operating, and other costs. Compliance could also impact future results of operations, cash flows, and financial condition if such costs are not recoverable through regulated rates. Noncompliance could result in fines, penalties, and injunctive measures negatively affecting our operations and facilities.

Any change in our authority to sell electricity at market-based rates may impact earnings.

The FERC has authorized certain of our subsidiaries to sell electricity in the wholesale market at market prices. These subsidiaries must file an updated market power analysis with the FERC at least every three years to demonstrate the subsidiary does not possess market power in that region. The FERC retains the authority to modify, revoke, or rescind this market-based rate authority. If the FERC determines that the relevant market is not workably competitive, that we or our subsidiaries possess market power, that we are not charging just and reasonable rates, or that we have not complied with the rules required in order to maintain market-based rates, the FERC may require our subsidiaries to sell power at a price based upon the costs incurred in producing the power, or otherwise revoke or rescind our authority in that market. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates we may receive, or otherwise by any revocation or rescission of such authority.

Our nonregulated businesses may be unable to achieve acceptable returns as a result of competition from existing and future competitors, which could impact our earnings.

Our nonregulated businesses, including both our retail energy business, Integrys Energy Services, and our compressed natural gas business, ITF, face competition for customers. Competitors may be willing to accept lower returns, which would allow them to offer lower prices and other incentives, which may impact our ability to attract and retain customers.

In some retail markets, the principal competitor of Integrys Energy Services may be the incumbent retail energy provider. The incumbent retail energy provider has the advantage of long-standing relationships with its customers, including well-known brand recognition, or may have access to previously regulated assets. Additionally, Integrys Energy Services may face competition from a number of other competitive energy service providers, other energy market participants, or nationally branded providers of consumer products and services.

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The market for renewable and efficient energy generation, including compressed natural gas, is relatively new, highly competitive, and rapidly evolving. We can provide no assurance that Integrys Energy Services and ITF will be able to compete successfully against current or potential competitors, who may have longer operating histories, better brand recognition, or greater financial, technical, and marketing resources than we do.

Increased competition for our nonregulated businesses may result in price reductions, reduced gross margins, and loss of market share. Any of these could harm our business and adversely affect our operating results and financial condition.

Adverse capital and credit market conditions could negatively affect our ability to meet liquidity needs, access capital, and/or grow or sustain our current business. Cost of capital and disruptions, uncertainty, and/or volatility in the financial markets could adversely impact our results of operations and financial condition, as well as exert downward pressure on our stock price.

Having access to the credit and capital markets, at a reasonable cost, is necessary for us to fund our operations and capital requirements. The capital and credit markets provide us with liquidity to operate and grow our businesses that is not otherwise provided from operating cash flows and also supports our ability to provide credit support for our subsidiaries. Disruptions, uncertainty, and/or volatility in those markets could increase our cost of capital or limit the availability of capital. If we or our subsidiaries are unable to access the credit and capital markets on terms that are reasonable, we may have to delay raising capital, issue shorter-term securities, and/or bear an increased cost of capital. This, in turn, could impact our ability to grow or sustain our current businesses, cause a reduction in earnings, result in a credit rating downgrade, and/or limit our ability to sustain our current common stock dividend level.

A reduction in our or our subsidiaries' credit ratings could materially and adversely affect our business, financial position, results of operations, and liquidity.

We cannot be sure that any of our or our subsidiaries' credit ratings will not be lowered by a rating agency if, in the rating agency’s judgment, circumstances in the future so warrant. Any downgrade could:

- Require the payment of higher interest rates in future financings and possibly reduce the potential pool of creditors;
- Increase borrowing costs under certain existing credit facilities;
- Limit access to the commercial paper market;
- Limit the availability of adequate credit support for our subsidiaries’ operations; and
- Require provision of additional credit assurance, including cash margin calls, to contract counterparties.

Counterparties and customers may not meet their obligations.

We are exposed to the risk that counterparties to various arrangements who owe us money, electricity, natural gas, coal, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to replace the underlying commitment at then-current market prices or we may be unable to meet all of our customers' natural gas and electric requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, or our results of operations, financial position, or liquidity could otherwise be adversely affected.

Some of our customers are experiencing, or may experience, financial problems that could have a significant impact on their creditworthiness. We cannot provide assurance that financially distressed customers will not default on their obligations to us and that such defaults will not have a material adverse impact on our business, financial position, results of operations, or cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, could adversely impact our receivable collections or increase our bad debt allowances for these customers, which could adversely affect our operating results. In addition, such events might force customers to reduce their future use of our products and services, which could have a material adverse impact on our results of operations and financial condition.

Our operations are subject to various conditions which can result in fluctuations in the number of customers and their energy use.

Our operations are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- Fluctuations in general economic conditions and growth in the service areas in which we operate;
- Weather conditions; and
- Our customers' continued focus on energy efficiency and ability to meet their own energy needs.

We may not be able to use tax credit and/or net operating loss carryforwards.

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits and net operating loss carryforwards available under the applicable tax codes. We have not fully used these tax credits and net operating loss carryforwards in our previous tax filings, and we may not be able to fully use the tax credits and net operating losses available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit the use of such credits and losses. In addition, any future disallowance

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of some or all of those tax credits or net operating loss carryforwards as a result of legislative change or adverse determination by one of the applicable taxing jurisdictions could materially affect our tax obligations and financial results.

Poor investment performance of retirement plan investments and other factors impacting retirement plan costs could unfavorably impact our liquidity and results of operations.

We have employee benefit plans that cover substantially all of our employees and retirees. Our cost of providing these benefit plans varies depending upon actual plan experience and assumptions concerning the future. These assumptions include earnings on and/or valuations of plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and required or voluntary contributions to the plans. Depending on the investment performance over time and other factors impacting our costs, we could be required to make larger contributions in the future to fund these plans. These additional funding obligations could have a material adverse impact on our cash flows, financial condition, and/or results of operations. Changes made to the plans may also impact current and future pension and other postretirement benefit costs.

We have recorded goodwill and other intangibles that could become impaired.

To the extent the value of goodwill or other intangibles becomes impaired, we have had to, and in the future, may also be required to, incur material noncash charges relating to such impairments. These impairment charges could have a material impact on our financial results.

We are actively involved with several capital projects, which are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing, and completion of the projects.

Our regulated utilities are capital intensive and require significant investments in energy generation, natural gas storage, delivery, and other projects, including projects for environmental compliance and distribution system improvements. These projects include our AMRP at PGL, our emission control project called ReACT™ on Weston 3 for WPS, and our System Modernization and Reliability Project (SMRP) at WPS.

Achieving the intended benefits of any large construction project is subject to many uncertainties. These uncertainties include the ability to adhere to established budgets and time frames, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There may also be contractor or supplier performance issues or adverse changes in their creditworthiness and difficulties meeting critical regulatory requirements. If construction of the projects should materially and adversely deviate from the schedules, estimates, and projections submitted to and approved by the applicable commissions, the commissions could deem these additional capital costs as imprudent and disallow recovery through currently established recovery mechanisms.

Furthermore, jointly owned projects, such as implementing emission control technology at the Columbia plant, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments. New joint owners would be difficult to secure at equivalent financial terms, or changes in the joint ownership make-up could increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Fluctuating commodity prices may impact energy margins and result in changes to liquidity requirements.

The margins and liquidity requirements of our businesses are impacted by changes in the forward and current market prices of natural gas, coal, electricity, renewable energy credits, and ancillary services. Changes in price could result in:

- Higher working capital costs, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Increased liquidity requirements due to potential counterparty margin calls related to the use of derivative instruments to manage commodity price and volume exposure;
- Reduced profitability to the extent that reduced margins, increased bad debt, and interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact the company's competitive position;
- Reduced demand for energy, which could impact margins and operating expenses; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

Our operations are subject to risks arising from the reliability of our electric generation, transmission and distribution facilities, natural gas infrastructure facilities and other facilities, as well as the reliability of third-party transmission providers.

The operation of electric generation and natural gas and electric distribution facilities involves many risks, including the risk of potential breakdown or failure of equipment or processes, which may occur due to storms, natural disasters, or other catastrophic events. Other risks include aging infrastructure, fuel supply or transportation disruptions, accidents, employee labor disputes, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, and performance below expected levels. Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by unexpected or uncontrollable events occurring on the systems of these third parties.

Operation of our power plants below expected capacity could result in lost revenues and increased expenses, including higher operating and maintenance costs, purchased power costs, and capital requirements. Unplanned outages of generating units and extensions of scheduled outages due to mechanical failures or other problems may occur and are an inherent risk of our business. Unplanned outages may reduce our revenues or may require us to incur significant costs by forcing us to operate our higher cost electric generators or obtain replacement power from third parties in the open market to satisfy our power sales obligations. Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of the lost revenues or increased expenses.

New and pending environmental regulations may force many generation facility owners in the Midwest, including our electric utilities, to retire a significant number of older coal-fired generation facilities, resulting in a potential reduction in the region's capacity reserve margin to below acceptable risk levels. This could also impair the reliability of the Midwest portion of the grid, especially during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

We are obligated to provide safe and reliable service to customers within our service territories. Meeting this commitment requires significant capital resources. Failure to provide safe and reliable service and failure to meet regulatory reliability standards could adversely affect our operating results through the imposition of penalties and fines or other adverse regulatory outcomes.

As a holding company, we rely on the earnings of our subsidiaries to meet our financial obligations.

We are a holding company, and our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our ability to meet our financial obligations and pay dividends on our common stock is dependent upon the ability of our subsidiaries to make payments to us, whether through dividends or otherwise. Our subsidiaries are separate legal entities that have no obligation to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to make payments to us depends on their earnings, cash flows, capital requirements, general financial condition, and regulatory limitations. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions, which may include requirements to maintain levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

We are subject to the Wisconsin Public Utility Holding Act, which may limit merger, acquisition, and sale opportunities that could benefit our shareholders.

The Wisconsin Public Utility Holding Company Law limits our ability to invest in nonutility related businesses and may make it more difficult for others to obtain control of us. This law mandates that the PSCW must first determine that the acquisition is in the best interests of utility customers, investors, and the public. Those interests may, to some extent, be mutually exclusive. This provision and other requirements of the Wisconsin Public Utility Holding Company Act may delay, or reduce the likelihood of, a sale or change of control thus reducing the likelihood that shareholders will receive a takeover premium for their shares.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

A. REGULATED

Natural Gas Facilities

At December 31, 2013, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,300 miles of natural gas distribution mains,
- Approximately 1,000 miles of natural gas transmission mains,
- Approximately 1.3 million natural gas lateral services,
- 298 natural gas distribution and transmission gate stations,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.0 billion-cubic-foot underground natural gas storage reservoir located in central Illinois,* and
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois.*

* PGL owns and operates this reservoir and liquefied natural gas plant in central Illinois (Manlove Field). PGL also owns a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. The underground storage reservoir also serves NSG under a contractual arrangement. PGL uses its natural gas storage and pipeline assets as a natural gas hub in the Chicago area.

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2013:

Type	Name	Location	Primary Fuel	Rated Capacity (Megawatts) (1)	
Steam	Columbia Units 1 and 2	Portage, Wisconsin	Coal	350.8	(2)
	Edgewater Unit 4	Sheboygan, Wisconsin	Coal	94.3	(2)
	Pulliam (4 units)	Green Bay, Wisconsin	Coal	325.5	(3)
	Weston Units 1, 2, and 3	Marathon County, Wisconsin	Coal	449.8	(3)
	Weston Unit 4	Marathon County, Wisconsin	Coal	375.8	(2)
Total Steam				1,596.2	
Combustion Turbine and Diesel	Fox Energy Center	Kaukauna, Wisconsin	Natural Gas	556.1	
	De Pere Energy Center	De Pere, Wisconsin	Natural Gas	164.2	
	Gladstone	Gladstone, Michigan	Oil	16.7	
	Juneau #31	Adams County, Wisconsin	Distillate Fuel Oil	6.2	(4)
	Portage	Houghton, Michigan	Oil	17.1	
	Pulliam #31	Green Bay, Wisconsin	Natural Gas	85.0	
	West Marinette #31	Marinette, Wisconsin	Natural Gas	38.2	

	West Marinette #32	Marinette, Wisconsin	Natural Gas	38.2	
	West Marinette #33	Marinette, Wisconsin	Natural Gas	77.1	
	Weston #31	Marathon County, Wisconsin	Natural Gas	12.9	
	Weston #32	Marathon County, Wisconsin	Natural Gas	42.4	
Total Combustion Turbine and Diesel				1,054.1	
Hydroelectric	Various	Michigan	Hydro	17.0	
	Various	Wisconsin	Hydro	60.7	(5)
Total Hydroelectric				77.7	
Wind	Lincoln	Wisconsin	Wind	0.9	
	Crane Creek	Iowa	Wind	20.2	
Total Wind				21.1	
Total System				2,749.1	

(1) Based on capacity ratings for summer 2014, which can differ from nameplate capacity, especially on wind projects. The summer period is the most relevant for capacity planning purposes at our electric utilities. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

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(2) These facilities are jointly owned by WPS and various other utilities. The capacity indicated for each of these units is equal to WPS's portion of total plant capacity based on its percent of ownership.

- Wisconsin Power and Light Company operates the Columbia and Edgewater units. WPS holds a 31.8% ownership interest in these facilities.
- WPS operates the Weston 4 facility and holds a 70% ownership interest in this facility. Dairyland Power Cooperative holds the remaining 30% interest.

(3) In connection with the WPS Consent Decree with the EPA, early retirement of the Weston 1, Pulliam 5, and Pulliam 6 generating units is probable. These units have an aggregate generating capacity of 166.9 megawatts (based on summer 2014 capacity ratings). See Note 15, Commitments and Contingencies, for more information regarding the Consent Decree.

(4) WRPC owns and operates the Juneau unit. WPS holds a 50% ownership interest in WRPC and is entitled to 50% of the total capacity from the Juneau unit.

(5) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50% ownership interest in WRPC and is entitled to 50% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 8.6 megawatts, and WPS's share of capacity for Petenwell is 10.5 megawatts.

As of December 31, 2013, our electric utilities owned approximately 25,100 miles of electric distribution lines located in Michigan and Wisconsin and 174 electric distribution substations.

General

Substantially all of our utility plant at WPS, PGL, and NSG is subject to first mortgage liens.

B. INTEGRYS ENERGY SERVICES

The following table summarizes information on the energy asset facilities owned by Integrys Energy Services as of December 31, 2013:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)	
Combined Cycle	Combined Locks	Combined Locks, Wisconsin	Natural Gas	45.5	(2)
Reciprocating Engine	Winnebago	Rockford, Illinois	Landfill Gas	6.4	
Solar	Various	Various States	Solar Irradiance	36.4	(3)
Total Energy Assets				88.3	
				Length of Pipeline (Miles)	
Landfill Gas Transportation	LGS	Brazoria County, Texas	N/A	33	

(1) Based on capacity ratings for summer 2014.

(2) Combined Locks has an additional five megawatts of capacity available at this facility through the lease of a steam turbine. Integrys Energy Services is currently pursuing the sale of Combined Locks. See Note 4, Discontinued Operations, for more information.

(3) The solar facilities consist of small distributed solar projects ranging from 0.1 to 4.0 megawatts in size. A portion of the solar facilities are wholly owned by subsidiaries of Integrys Energy Services and others are owned by INDU Solar Holdings, LLC, which is jointly owned by Integrys Energy Services and Duke Energy Generation Services. Of the capacity listed, 9.8 megawatts is Integrys Energy Services' portion of total solar capacity based on its ownership in INDU Solar Holdings, LLC.

C. HOLDING COMPANY AND OTHER

The following table summarizes information on the compressed natural gas fueling stations owned by ITF as of December 31, 2013:

Type	Name	Location	Number of Locations *
Compressed Natural Gas (CNG)	Various	Various States	25

* The CNG fueling stations consist of 22 stations that are wholly owned and operated by ITF. ITF operates two stations that are owned by AMP Trillium LLC, which is jointly owned by ITF and AMP Americas, LLC. ITF holds a 30% ownership interest in AMP Trillium LLC. Additionally, ITF operates one station that is owned by EVO Trillium LLC, which is jointly owned by ITF and Environmental Alternative Fuels, LLC. ITF holds a 15% ownership interest in EVO - Trillium LLC.

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ITEM 3. LEGAL PROCEEDINGS

See Note 15, Commitments and Contingencies, for more information on material legal proceedings and matters related to us and our subsidiaries.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock and Dividend Data

Our common stock is traded on the New York Stock Exchange under the ticker symbol "TEG." The transfer agent and registrar for our common stock is American Stock Transfer & Trust Company, LLC, 6201 15th Avenue, Brooklyn, NY 11219. The quarterly high and low sales prices for our common stock and the cash dividends per share declared for each quarter during the past two years were as follows:

	2013			2012		
Quarter	High	Low	Dividends	High	Low	Dividends
First	$58.27	$52.55	$0.68	$54.88	$50.80	$0.68
Second	62.75	55.39	0.68	57.55	50.89	0.68
Third	63.58	53.80	0.68	61.92	51.79	0.68
Fourth	59.74	52.70	0.68	55.83	51.14	0.68

As of the close of business on February 19, 2014, we had 24,603 holders of record of our common stock.

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. See Note 19, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends.

Equity Compensation Plans

See Item 11 - Executive Compensation for information regarding equity securities authorized for issuance under our equity compensation plans.

Issuer Purchases of Equity Securities

As of February 5, 2013, we began issuing new shares of common stock to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. Prior to this date, shares were purchased on the open market to meet the requirements of these plans. There were no common stock purchases during the three months ended December 31, 2013. In conjunction with the announcement of the proposed sale of UPPCO, beginning February 5, 2014, we went back to purchasing shares on the open market to meet the requirements of these plans.

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ITEM 6. SELECTED FINANCIAL DATA

INTEGRYS ENERGY GROUP, INC.
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 (Millions, except per share amounts, stock price, return on average equity, and number of shareholders and employees)	2013 *	2012	2011	2010	2009
Total revenues	$5,634.6	$4,212.4	$4,685.9	$5,169.8	$7,464.7
Net income (loss) from continuing operations	350.0	294.0	230.0	245.2	(74.8)
Net income (loss) attributed to common shareholders	351.8	281.4	227.4	220.9	(69.6)
Total assets	11,243.5	10,327.4	9,983.2	9,816.8	11,844.6
Preferred stock of subsidiary	51.1	51.1	51.1	51.1	51.1
Long-term debt (excluding current portion)	2,956.2	1,931.7	1,845.0	2,134.6	2,367.7
Average shares of common stock					
Basic	79.5	78.6	78.6	77.5	76.8
Diluted	80.1	79.3	79.1	78.0	76.8
Earnings (loss) per common share (basic)					
Net income (loss) from continuing operations	$4.37	$3.70	$2.89	$3.13	$(1.01)
Earnings (loss) per common share (basic)	4.43	3.58	2.89	2.85	(0.91)
Earnings (loss) per common share (diluted)					
Net income (loss) from continuing operations	4.33	3.67	2.87	3.11	(1.01)
Earnings (loss) per common share (diluted)	4.39	3.55	2.87	2.83	(0.91)
Dividends per common share declared	2.72	2.72	2.72	2.72	2.72
Stock price at year-end	$54.41	$52.22	$54.18	$48.51	$41.99
Book value per share	$41.05	$38.84	$38.01	$37.57	$37.51
Return on average equity	11.2%	9.4%	7.7%	7.7%	(2.4)%
Number of common stock shareholders	24,908	28,425	28,993	30,352	32,755
Number of employees	4,888	4,717	4,619	4,612	5,025

* Includes the impact of the acquisition of the Fox Energy Center at the electric utilities in March 2013.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

We are a diversified energy holding company with regulated natural gas and electric utility operations (serving customers in Illinois, Michigan, Minnesota, and Wisconsin), an approximate 34% equity ownership interest in ATC (a federally regulated electric transmission company), and nonregulated energy operations.

Strategic Overview

Our goal is to create long-term value for shareholders and customers through growth in our core regulated businesses. We also have a nonregulated energy services business segment that is focused on growth within a controlled risk profile.

The essential components of our business strategy are:

Maintaining and Growing a Strong Regulated Utility Base – A strong regulated utility base is essential to maintaining a strong balance sheet, predictable cash flows, the desired risk profile, attractive dividends, and quality credit ratings. We believe the following projects have helped, or will help, maintain and grow our regulated utility base and meet our customers' needs:

- An accelerated annual investment in natural gas distribution facilities (primarily replacement of cast iron mains) at PGL,
- WPS's purchase of the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility located in Wisconsin, in 2013,
- WPS's continued investment in environmental projects to improve air quality and meet or exceed the requirements set by environmental regulators,
- WPS's System Modernization and Reliability Project to underground and upgrade certain electric distribution facilities in northern Wisconsin that will begin in 2014, and
- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.4 billion of transmission assets at December 31, 2013. ATC plans to invest approximately $3.0 billion to $3.6 billion in transmission system improvements during the next ten years. Although ATC's equity requirements to fund its capital investments will primarily be met by earnings reinvestment, we plan to continue to fund our share of the equity portion of future ATC growth as necessary.

For more detailed information on our capital expenditure program, see Liquidity and Capital Resources – Capital Requirements.

Providing Safe, Reliable, Competitively Priced, and Environmentally Sound Energy and Related Services – Our mission is to provide customers with the best value in energy and related services. We strive to effectively operate a mixed portfolio of generation assets and prudently invest in new generation and distribution assets, while maintaining or exceeding environmental standards. This allows us to provide a safe, reliable, value-priced service to our customers. Our presence in the compressed natural gas fueling marketplace, while not currently significant, is complementary to our existing businesses and is consistent with our mission.

Operating a Nonregulated Energy Services Business Segment with a Controlled Risk and Capital Profile – Through our nonregulated Integrys Energy Services subsidiary, we provide retail natural gas and electric products to end-use customers primarily in the northeast quadrant of the United States. This subsidiary is focused on operating within select retail electric and natural gas markets in its current market footprint where it has experience and believes it will have the most success growing its recurring retail customer based business at acceptable returns. In addition, Integrys Energy Services continues to develop, acquire, own, and operate renewable energy projects, primarily distributed solar generation, in the United States. This strategy is intended to result in dependable cash and earnings contributions with a controlled risk and capital profile.

Integrating Resources to Provide Operational Excellence – We are committed to integrating resources of all our businesses and finding the best and most efficient processes while meeting all applicable legal and regulatory requirements. We strive to provide the best value to our customers and shareholders by embracing constructive change, leveraging capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations. "Operational Excellence" initiatives have been implemented to reduce costs and encourage top performance in the areas of project management, process improvement, contract administration, and compliance.

Placing Strong Emphasis on Asset and Risk Management – Our asset management strategy calls for the continuous assessment of existing assets, the acquisition of assets, and contractual commitments to obtain resources that complement our existing business and strategy. The goal is to provide the most efficient use of resources while maximizing return and maintaining an acceptable risk profile. This strategy focuses on acquiring assets consistent with strategic plans and disposing of assets, including property, plant, and equipment and entire business units, that are no longer strategic to ongoing operations, are not performing as intended, or have an unacceptable risk profile. We maintain a portfolio approach to risk and earnings.

Our risk management strategy includes the management of market, credit, liquidity, and operational risks through the normal course of business. Forward purchases and sales of electric capacity, energy, natural gas, and other commodities, and the use of derivative financial instruments, including commodity swaps and options, provide tools to reduce the risk associated with price movement in a volatile energy market. Each business

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unit manages the risk profile related to these instruments consistent with our risk management policies, which are approved by the Board of Directors. The Corporate Risk Management Group, which reports through the Chief Financial Officer, provides corporate oversight.

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Year Ended December 31 2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Natural gas utility operations	$123.4	$93.4	$103.3	32.1 %	(9.6)%
Electric utility operations	110.9	107.9	100.5	2.8 %	7.4 %
Electric transmission investment	53.9	52.4	47.8	2.9 %	9.6 %
Integrys Energy Services' operations	78.3	41.1	(6.1)	90.5 %	N/A
Holding company and other operations	(14.7)	(13.4)	(18.1)	9.7 %	(26.0)%
Net income attributed to common shareholders	$351.8	$281.4	$227.4	25.0 %	23.7 %
Basic earnings per share	$4.43	$3.58	$2.89	23.7 %	23.9 %
Diluted earnings per share	$4.39	$3.55	$2.87	23.7 %	23.7 %
Average shares of common stock					
Basic	79.5	78.6	78.6	1.1 %	— %
Diluted	80.1	79.3	79.1	1.0 %	0.3 %

2013 Compared with 2012

Our earnings increased $70.4 million year over year. The following items were the main contributors to the increase:

- A $37.2 million after-tax non-cash increase in Integrys Energy Services' margins related to derivative and inventory fair value adjustments.

- The $30.3 million after-tax positive impact of rate orders at the utilities.

- A $30.1 million after-tax increase due to an increase in sales volumes at the natural gas utilities, net of decoupling. Weather was colder than normal in 2013 and warmer than normal in 2012. In addition, certain of our natural gas utilities did not have decoupling impacts in 2012 to offset the impact of weather.

- A $14.5 million increase in net income from discontinued operations. See Note 4, Discontinued Operations, for more information.

- The $9.9 million after-tax positive impact of the first quarter 2013 reversal of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 26, Regulatory Environment, for more information.

These increases were partially offset by:

- A $27.4 million after-tax increase in operating expenses at the natural gas utilities, excluding items directly offset in margins, driven by an increase in natural gas distribution costs.

- An $11.0 million after-tax increase in operating expenses at Integrys Energy Services, driven by an increase in sales and marketing costs and outside service fees, primarily related to the expansion of the residential and small commercial customer business.

- A $10.9 million after-tax increase in electric transmission expense and maintenance expense, excluding the newly acquired Fox Energy Center, at the electric utilities. The increase in maintenance expense was driven primarily by a plant outage at Weston 3.

2012 Compared with 2011

The $54.0 million increase in our earnings was driven by:

- A $60.1 million after-tax non-cash increase in Integrys Energy Services' margins related to derivative and inventory fair value adjustments.

- A $33.7 million after-tax positive impact related to rate orders at the natural gas utilities, excluding items directly offset in operating expenses.

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These increases were partially offset by:

- A $26.2 million after-tax decrease in natural gas utility margins due to lower sales volumes driven by warmer weather, net of decoupling.

- A $12.5 million decrease in income from discontinued operations at Integrys Energy Services. See Note 4, Discontinued Operations, for more information.

Regulated Natural Gas Utility Segment Operations

(Millions, except heating degree days)	Year Ended December 31 2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Revenues	$2,105.0	$1,672.0	$1,998.0	25.9 %	(16.3)%
Purchased natural gas costs	1,046.2	775.0	1,101.4	35.0 %	(29.6)%
Margins	1,058.8	897.0	896.6	18.0 %	— %
Operating and maintenance expense	632.7	527.5	523.6	19.9 %	0.7 %
Depreciation and amortization expense	136.0	131.8	126.1	3.2 %	4.5 %
Taxes other than income taxes	38.2	35.6	35.6	7.3 %	— %
Operating income	251.9	202.1	211.3	24.6 %	(4.4)%
Miscellaneous income	1.2	0.6	2.2	100.0 %	(72.7)%
Interest expense	50.2	47.3	48.4	6.1 %	(2.3)%
Other expense	(49.0)	(46.7)	(46.2)	4.9 %	1.1 %
Income before taxes	$202.9	$155.4	$165.1	30.6 %	(5.9)%
Retail throughput in therms					
Residential	1,663.6	1,324.8	1,541.5	25.6 %	(14.1)%
Commercial and industrial	534.8	406.0	469.5	31.7 %	(13.5)%
Other	74.0	75.3	61.3	(1.7)%	22.8 %
Total retail throughput in therms	2,272.4	1,806.1	2,072.3	25.8 %	(12.8)%
Transport throughput in therms					
Residential	252.7	204.0	237.4	23.9 %	(14.1)%
Commercial and industrial	1,650.6	1,557.9	1,559.7	6.0 %	(0.1)%
Total transport throughput in therms	1,903.3	1,761.9	1,797.1	8.0 %	(2.0)%
Total throughput in therms	4,175.7	3,568.0	3,869.4	17.0 %	(7.8)%
Weather					
Average actual heating degree days	7,285	5,601	6,675	30.1 %	(16.1)%
Average normal heating degree days	6,600	6,709	6,702	(1.6)%	0.1 %

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 7% increase and an approximate 20% decrease in the average per-unit cost of natural gas sold during 2013 and 2012, respectively, which had no impact on margins.

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2013 Compared with 2012

Margins

Regulated natural gas utility segment margins increased $161.8 million, driven by:

- An approximate $67 million net increase in margins due to sales volume variances and our decoupling mechanisms.

The combined effect of the change in weather year over year and the impact of our decoupling mechanisms increased margins approximately $50 million. In 2012, margins at the natural gas utilities were negatively impacted by unusually warm weather, and the majority of our natural gas utilities either did not have decoupling mechanisms in place or the mechanism did not cover weather-related volume variances. In 2013, decoupling mechanisms were in place for all the natural gas utilities, but colder than normal weather did have a positive impact on MGU's margins as their decoupling mechanism does not cover weather-related volume variances. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 26, Regulatory Environment, for more information on our decoupling mechanisms.

In 2013, PGL and NSG recorded an increase in revenues of approximately $17 million when reserves established in 2012 against regulatory assets related to decoupling from a prior period were reversed. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 26, Regulatory Environment, for more information.

- An approximate $53 million increase in margins related to certain riders at PGL and NSG and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

Our natural gas utilities billed approximately $27 million more to customers for energy efficiency programs at MGU, NSG, PGL, and WPS in 2013.

PGL and NSG recovered approximately $26 million more for environmental cleanup costs at their former manufactured gas plant sites related to an increase in remediation activity during 2013. See Note 15, Commitments and Contingencies, for more information about the manufactured gas plant sites.

- An approximate $31 million net increase in margins due to rate orders. See Note 26, Regulatory Environment, for more information.

The rate increases at PGL and NSG, effective June 27, 2013, and January 21, 2012, and other impacts of rate design, had an approximate $32 million positive impact on margins.

MERC recognized an approximate $2 million increase in margins primarily driven by the impact of a July 2012 rate order from the MPUC. Customer refunds were accrued in 2012 as a result of 2011 interim rates that had been in effect.

A reduction in rates at WPS, effective January 1, 2013, resulted in an approximate $3 million negative impact on margins.

- An approximate $8 million increase in margins due to the MPUC's approval of MERC's energy conservation incentives in December 2013. These financial incentives were earned by MERC for achieving certain conservation improvement program goals.

Operating Income

Operating income at the regulated natural gas utility segment increased $49.8 million. This increase was driven by the $161.8 million increase in margins discussed above, partially offset by a $112.0 million increase in operating expenses.

The increase in operating expenses was primarily due to:

- A $31.7 million increase in energy efficiency program expenses at our natural gas utilities. Margins increased by an equal amount, resulting in no impact on earnings.
- A $28.6 million increase driven by higher amortization of regulatory assets at certain of our natural gas utilities related to environmental cleanup costs for manufactured gas plant sites. For approximately $26 million of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.
- A $22.1 million increase in natural gas distribution costs, primarily at PGL. The increase was partially due to increased labor and contractor costs driven by additional compliance work. A portion of the compliance work was driven by new local regulations related to natural gas distribution main openings and repairs in the public way. Natural gas distribution costs also increased due to a plastic pipe fittings replacement project.

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- An $8.3 million net increase in employee benefit costs. The total employee benefit costs increase of $10.4 million was primarily due to higher pension expense, largely at PGL, driven by a lower discount rate in 2013. The lower discount rate did not significantly impact the other natural gas utilities due to an increase in contributions to those plans in prior years, which increased plan assets. WPS deferred $2.1 million of certain increases in pension and other employee benefit costs that will be recovered in a future rate proceeding as a result of its 2013 rate order. See Note 26, Regulatory Environment, for more information.

- A $7.2 million increase in bad debt expense, driven by a cost of natural gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. This natural gas component is charged to customers based on actual volumes and natural gas prices. As a result of this component, bad debt expense was primarily impacted by both higher natural gas costs in 2013 and an increase in sales volumes. However, the increase in bad debt expense does not impact earnings as it is offset by higher rates through a rider mechanism, resulting in higher margins.

- A $5.2 million increase in legal and outside services expense.

- A $4.2 million net increase in depreciation and amortization expense. Continued investment in property and equipment, primarily the AMRP at PGL, drove the increase in expense. Partially offsetting the increase was a $3.4 million reduction in expense at MERC related to a new depreciation study approved by the MPUC on July 29, 2013. The study included changes to salvage values and costs of removal, as well as extensions to the service lives of certain assets. In addition, there was a $2.5 million reduction in expense at MGU. In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010. See Note 26, Regulatory Environment, for more information.

- A $2.7 million increase in asset usage charges from IBS, driven by new software for both natural gas management and work asset management that was placed in service during the third quarter of 2013.

- A $2.6 million increase in taxes other than income taxes, driven by the Illinois invested capital tax. This tax assessment is based on an entity's equity and long-term debt balances, which have increased for PGL in 2013.

Other Expense

Other expense at the regulated natural gas utilities increased $2.3 million in 2013. Interest expense on long-term debt increased, driven by higher average long-term debt outstanding in 2013.

2012 Compared with 2011

Margins

Regulated natural gas utility segment margins increased $0.4 million, driven by:

- An approximate $42 million net increase in margins due to rate orders. See Note 26, Regulatory Environment, for more information.

  The rate increases at PGL and NSG, effective January 21, 2012, and other impacts of rate design, had an approximate $48 million positive impact on margins.

  A reduction in rates at WPS, effective January 1, 2012, resulted in an approximate $5 million negative impact on margins. The rate decrease was driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions is offset by lower operating expenses.

MERC had an approximate $1 million decrease in margins in 2012 primarily driven by the impact of a rate order from the MPUC finalized in January 2013. A preliminary order was received in July 2012 that adjusted 2011 interim rates in effect since February 1, 2011.

- An approximate $4 million net increase in margins related to certain riders at PGL and NSG. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

PGL and NSG billed approximately $7 million more to customers for energy efficiency programs in 2012.

PGL and NSG refunded approximately $2 million more to customers under bad debt riders in 2012.

PGL and NSG recovered approximately $1 million less for environmental cleanup costs at their former manufactured gas plant sites in 2012. The lower recovery reflects a pass-through to customers in rates of an environmental settlement received by NSG from a potentially responsible party's performance and payment bond. The impact of the settlement was partially offset by an increase in remediation activity at PGL during 2012. See Note 15, Commitments and Contingencies, for more information about the manufactured gas plant sites.

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The above increases in margins were partially offset by an approximate $43 million net decrease in margins, including the impact of decoupling, due to a 7.8% decrease in volumes sold.

- Substantially warmer weather during 2012 drove an approximate $55 million decrease in margins. Heating degree days decreased 16.1%.

- Lower sales volumes excluding the impact of weather resulted in an approximate $6 million decrease in margins. Sales volumes were slightly lower due to lower use per customer.

- Decoupling impacts at certain natural gas utilities drove an approximate $18 million increase in margins. Decoupling does not cover all jurisdictions or customer classes.

  Decoupling accruals in 2012 had an approximate $9 million positive impact on the year-over-year variance. Decoupling lessened the negative impact from some of the decreased sales volumes at WPS and MGU through higher future recoveries from customers. This was limited by an $8.0 million decoupling cap that was reached by WPS during the second quarter of 2012. In 2012, reserves were recorded against all decoupling accruals at PGL and NSG after an ICC order declared these amounts may be subject to refund. See Note 26, Regulatory Environment, for more information.

  Decoupling accruals in 2011 had an approximate $9 million positive impact on the year-over-year variance. Decoupling lessened the positive impact in 2011 from some of the higher sales volumes at PGL, NSG, WPS, and MGU through higher future refunds to customers.

Operating Income

Operating income at the regulated natural gas utility segment decreased $9.2 million. This decrease was driven by a $9.6 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $24.6 million increase in natural gas distribution costs, primarily at PGL. The increase was partially due to increased labor costs driven by annual wage increases, as well as additional employees required for compliance work related to inside safety inspections and corrosion review. Additional contractors were also needed for street restoration and pipe maintenance to replace employees that were moved to the AMRP project.

- A $5.7 million increase in depreciation and amortization expense resulting from increased investment in property and equipment, primarily driven by the AMRP.

- An approximate $4 million net increase at PGL and NSG driven by an increase in regulatory liabilities related to energy efficiency programs, partially offset by higher amortization of regulatory liabilities related to bad debt riders and lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites. Margins increased by an equal amount, resulting in no impact on earnings.

These increases were partially offset by:

- A $9.9 million decrease in energy efficiency program expenses related to WPS's participation in the Focus on Energy Program and MERC's conservation improvement program. Costs for both programs are recovered in rates.

-

An $8.6 million decrease in bad debt expense, driven by a new cost of gas component included as part of PGL's and NSG's bad debt expense tracking mechanisms. The change in the bad debt mechanisms was approved in PGL's and NSG's rate orders, effective January 21, 2012. In those orders, the ICC required that a natural gas cost component of the bad debt mechanism be charged to customers based on actual volumes and natural gas prices. As a result of this component, bad debt expense was primarily impacted by lower natural gas costs in 2012 and, to a lesser extent, by the decrease in sales volumes. However, $6.8 million of the decrease in bad debt expense does not impact earnings as it is offset by lower rates, resulting in lower margins.

- A $2.7 million decrease in workers compensation expense related to both fewer incidents and less severe injuries during 2012, primarily at PGL.

- A $2.4 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.

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Regulated Electric Utility Segment Operations

(Millions, except degree days)	Year Ended December 31 2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Revenues	$1,332.1	$1,297.4	$1,307.3	2.7 %	(0.8)%
Fuel and purchased power costs	536.9	562.1	546.3	(4.5)%	2.9 %
Margins	795.2	735.3	761.0	8.1 %	(3.4)%
Operating and maintenance expense	440.2	405.6	421.7	8.5 %	(3.8)%
Depreciation and amortization expense	98.6	89.0	88.5	10.8 %	0.6 %
Taxes other than income taxes	49.1	47.6	47.6	3.2 %	— %
Operating income	207.3	193.1	203.2	7.4 %	(5.0)%
Miscellaneous income	9.8	2.6	0.8	276.9 %	225.0 %
Interest expense	36.4	35.9	41.8	1.4 %	(14.1)%
Other expense	(26.6)	(33.3)	(41.0)	(20.1)%	(18.8)%
Income before taxes	$180.7	$159.8	$162.2	13.1 %	(1.5)%
Sales in kilowatt-hours					
Residential	3,132.3	3,106.6	3,135.6	0.8 %	(0.9)%
Commercial and industrial	8,504.0	8,574.5	8,520.9	(0.8)%	0.6 %
Wholesale	4,327.2	4,614.7	4,256.8	(6.2)%	8.4 %
Other	37.6	38.0	38.4	(1.1)%	(1.0)%
Total sales in kilowatt-hours	16,001.1	16,333.8	15,951.7	(2.0)%	2.4 %
Weather					
WPS:					
Actual heating degree days	8,051	6,356	7,524	26.7 %	(15.5)%
Normal heating degree days	7,452	7,548	7,514	(1.3)%	0.5 %
Actual cooling degree days	529	789	603	(33.0)%	30.8 %
Normal cooling degree days	503	475	480	5.9 %	(1.0)%
UPPCO:					
Actual heating degree days	9,496	7,749	8,676	22.5 %	(10.7)%
Normal heating degree days	8,665	8,757	8,697	(1.1)%	0.7 %
Actual cooling degree days	230	335	305	(31.3)%	9.8 %
Normal cooling degree days	232	218	215	6.4 %	1.4 %

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

2013 Compared with 2012

Margins

Regulated electric utility segment margins increased $59.9 million, driven by:

- An approximate $32 million increase in margins related to lower fuel and purchased power costs. The decline in purchased power costs was driven by the termination of a power purchase agreement in connection with the acquisition of Fox Energy Company LLC. WPS's retail margins were positively impacted by the reduction in the capacity charges under the agreement, which are not included in its fuel and purchased power cost recovery mechanism. This had no impact on net income as the net difference between the lower purchased power costs and the costs of owning the plant are deferred for recovery or refund in a future PSCW retail rate case (the net difference is reflected in operating expenses below). Wholesale margins also increased as a result of the acquisition. Although purchased power costs decreased, wholesale revenues subsequent to the purchase of Fox Energy Company LLC include higher operating costs resulting from the ownership of the plant (see below).

- An approximate $19 million increase in margins due to a retail electric rate increase at WPS, effective January 1, 2013. See Note 26, Regulatory Environment, for more information on the 2013 PSCW rate order.

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- An approximate $10 million net increase in margins from residential and commercial and industrial customers due to variances related to sales volumes, including the impact of decoupling. The year-over-year impact of decoupling does not directly correlate with the year-over-year impact of the change in sales volumes, as WPS's decoupling mechanism was changed in 2013, and UPPCO did not have decoupling in 2012. See Note 26, Regulatory Environment, for more information.

Partially offsetting these increases was an approximate $5 million decrease in wholesale margins driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one large customer.

Operating Income

Operating income at the regulated electric utility segment increased $14.2 million. The increase was driven by the $59.9 million increase in margins discussed above, partially offset by a $45.7 million increase in operating expenses. The increase in operating expenses was driven by:

- A $14.7 million increase in maintenance expense due to a greater number of planned outages for certain WPS generation plants in 2013, driven primarily by an outage at Weston 3. Also included in this amount is maintenance expense associated with the recently acquired Fox Energy Center.

- A $9.6 million increase in depreciation and amortization expense mainly due to the acquisition of the Fox Energy Center, partially offset by a reduction in the depreciable basis of WPS's Crane Creek Wind Project. The reduction was the result of WPS's election to claim a Section 1603 Grant for the project in lieu of production tax credits.

- A $9.5 million increase in electric transmission expense.

- A $5.6 million increase due to WPS's deferral of the net difference between actual and rate case-approved costs resulting from the purchase of Fox Energy Company LLC. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of the power purchase agreement. However, WPS did receive approval from the PSCW to defer ownership costs above or below its power purchase agreement expenses for recovery or refund in a future rate case.

- A $5.1 million increase in various costs associated with the acquisition and operation of the Fox Energy Center.

- A $3.3 million increase in WPS's customer assistance expense, driven by the year-over-year change in the amortization of amounts recoverable from or refundable to customers related to energy efficiency.

In addition, a $4.7 million increase in employee benefit expenses was more than offset by the $7.3 million positive impact of the deferral of certain components of pension and other employee benefit costs that will be recovered in a future rate proceeding as a result of the WPS 2013 PSCW rate order. The increase in employee benefit expenses was driven by a lower discount rate in 2013, which increased both the pension and other postretirement benefit expenses.

Other Expense

Other expense decreased $6.7 million, primarily driven by an increase in AFUDC due to environmental compliance projects at the Columbia plant. The increase in AFUDC was partially offset by an increase in interest expense driven by the financing of the purchase of Fox Energy Company LLC.

2012 Compared with 2011

Margins

Regulated electric utility segment margins decreased $25.7 million, driven by:

- An approximate $21 million decrease in margins related to WPS rate case effects. Although the PSCW approved a rate increase effective January 1, 2012, it was driven by anticipated increases in fuel and purchased power costs that did not materialize. Under the fuel rules, we deferred a portion of the difference between the fuel window costs included in rates and the actual fuel window costs. This portion was refunded to customers.

  Excluding the impact from fuel and purchased power costs, the 2012 rate case re-opener resulted in a rate decrease. The rate decrease was primarily driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The approximate $11 million margin impact from the reduction in contributions to the Focus on Energy Program was offset by lower operating expenses due to reduced payments to the program in 2012.

  Fuel costs not included in the fuel window were lower relative to the rate case-approved amounts in 2011. This resulted in an approximate $9 million negative year-over-year impact on margins.

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- An approximate $6 million decrease in wholesale margins, driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one large customer and the loss of wholesale customers.

- An approximate $2 million net decrease in margins from retail customers due to variances related to sales volumes. The margin impact from the year-over-year change in sales volumes was partially offset by the impacts from decoupling mechanisms. Although decoupling was implemented to minimize the impact of changes in sales volumes, WPS's decoupling mechanism does not cover all customers or jurisdictions. UPPCO's decoupling mechanism was terminated at the end of 2011.

  A 0.9% decrease in sales volumes to residential customers, driven by warmer weather during the heating season, resulted in an approximate $3 million decrease in margins.

  Margins increased approximately $1 million due to decoupling mechanisms.

These decreases were partially offset by an approximate $5 million increase in margins due to a retail electric rate increase at UPPCO, effective January 1, 2012.

Operating Income

Operating income at the regulated electric utility segment decreased $10.1 million. The decrease was driven by the $25.7 million decrease in margins discussed above, partially offset by a $15.6 million decrease in operating expenses. The decrease in operating expenses was driven by:

- An $11.3 million decrease in customer assistance expense driven by reduced payments to the Focus on Energy program. These payments are recovered in rates.

- A $2.2 million decrease in bad debt expense, driven by the year-over-year impact of the 2011 write-off of receivables related to the bankruptcy of an UPPCO retail customer and the subsequent recovery of those receivables in the fourth quarter of 2012.

- A $2.2 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.

- A $1.9 million decrease in maintenance expense, mainly due to fewer repairs at UPPCO's hydroelectric facilities in 2012 as well as fewer storms in WPS's service territories in 2012 compared with 2011.

These decreases were partially offset by a $2.0 million increase in employee benefit related expenses. The increase was primarily due to an increase in postretirement medical expenses as well as the year-over-year change in the fair value of amounts owed to plan participants under deferred compensation plans. Partially offsetting these increases was lower pension expense driven by an increase in contributions, which increased plan assets.

Other Expense

Other expense decreased $7.7 million, driven by the maturity and repayment of $150 million of long-term debt at WPS in August 2011. Also contributing to the decrease in other expense was an increase in AFUDC, primarily related to environmental compliance projects at the Columbia plant.

Electric Transmission Investment Segment Operations

Year Ended December 31

(Millions)	2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Earnings from equity method investments	89.1	85.3	$79.1	4.5 %	7.8 %

2013 Compared with 2012

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $3.8 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

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2012 Compared with 2011

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $6.2 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

Integrys Energy Services Nonregulated Segment Operations

	Year Ended December 31			Change in 2013 Over 2012	Change in 2012 Over 2011
(Millions, except natural gas sales volumes)	2013	2012	2011		
Revenues	$2,167.5	$1,218.5	$1,373.1	77.9 %	(11.3)%
Cost of sales	1,910.8	1,021.4	1,265.3	87.1 %	(19.3)%
Margins	256.7	197.1	107.8	30.2 %	82.8 %
Margin Detail					
Realized retail electric margins	92.5	91.3	98.5	1.3 %	(7.3)%
Realized wholesale electric margins (1)	0.4	(0.6)	(0.2)	N/A	200.0 %
Realized renewable energy asset margins	15.8	15.0	12.2	5.3 %	23.0 %
Fair value accounting adjustments	93.4	38.0	(27.2)	145.8 %	N/A
Electric and renewable energy asset margins	202.1	143.7	83.3	40.6 %	72.5 %
Realized retail natural gas margins	41.7 (2)	47.5	49.1	(12.2)%	(3.3)%
Realized wholesale natural gas margins (1)	(0.2)	(0.6)	3.9	(66.7)%	N/A
Lower-of-cost-or-market inventory adjustments	4.5	4.4	(10.7)	2.3 %	N/A
Fair value accounting adjustments	8.6	2.1	(17.8)	309.5 %	N/A
Natural gas margins	54.6	53.4	24.5	2.2 %	118.0 %
Operating and maintenance expense	122.4	106.0	105.2	15.5 %	0.8 %
Depreciation and amortization expense	11.4	10.3	10.3	10.7 %	— %
Taxes other than income taxes	3.3	2.5	5.7	32.0 %	(56.1)%
Operating income (loss)	119.6	78.3	(13.4)	52.7 %	N/A
Earnings (losses) from equity method investments	1.3	1.1	(0.7)	18.2 %	N/A
Miscellaneous income	8.5	1.1	1.0	672.7 %	10.0 %
Interest expense	2.0	2.1	1.7	(4.8)%	23.5 %
Other income (expense)	7.8	0.1	(1.4)	7,700.0 %	N/A
Income (loss) before taxes	$127.4	$78.4	$(14.8)	62.5 %	N/A
Physically settled volumes					
Retail electric sales volumes in kwh	21,334.4	13,343.1	12,416.5	59.9 %	7.5 %
Wholesale assets and distributed solar electric sales volumes in kwh	64.0	92.7	84.7	(31.0)%	9.4 %
Retail natural gas sales volumes in bcf	183.6	116.5	118.3	57.6 %	(1.5)%

kwh — kilowatt-hours
bcf — billion cubic feet

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

(2) This amount includes negative margin of $4.8 million related to the amortization of the net amount paid for customer and related supply contracts in connection with the acquisition of Compass Energy Services. See Note 3, Acquisitions, for more information regarding this purchase.

2013 Compared with 2012

Revenues

Integrys Energy Services' revenues increased $949.0 million. The increase was driven by higher retail sales volumes, primarily related to the expansion of the residential and small commercial customer business, as well as the Compass Energy Services acquisition. See Note 3, Acquisitions, for more information regarding this acquisition.

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Margins

Integrys Energy Services’ margins increased $59.6 million. Significant items contributing to the change in margins were as follows:

Electric and Renewable Energy Asset Margins

Realized retail electric margins

Realized retail electric margins increased $1.2 million. The increase was primarily driven by higher sales volumes, partially offset by continued competitive pressure on per-unit margins. In addition, Integrys Energy Services was unable to fully recover fixed costs related to its electric aggregation customers as usage for these customers was lower than anticipated during the summer months.

Realized renewable energy asset margins

Realized renewable energy asset margins increased $0.8 million. The increase was primarily driven by continued investment in solar energy projects, which resulted in higher generation capacity and output.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services’ margins. Fair value adjustments caused a $55.4 million increase in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins, which include the amortization of customer and supply contracts related to the acquisition of Compass Energy Services, decreased $5.8 million. The decrease was primarily driven by fewer opportunities to take advantage of natural gas price volatility and changes in market prices for natural gas storage and transportation capacity in 2013 as well as continued competitive pressure on per-unit margins. These decreases were partially offset by higher sales volumes.

Inventory accounting adjustments

Integrys Energy Services’ physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The year-over-year change in margins from inventory adjustments was not significant.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services’ margins. Fair value adjustments caused a $6.5 million increase in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income

Integrys Energy Services' operating income increased $41.3 million. The main driver of the increase was the $59.6 million increase in margins discussed above, partially offset by a $18.3 million increase in operating expenses. The increase in operating expenses was driven by an increase in costs related to the expansion of the residential and small commercial customer business, as well as the Compass Energy Services acquisition. See Note 3, Acquisitions, for more information.

Other Income

Integrys Energy Services' other income increased $7.7 million. The main driver of the increase was the Seams Elimination Charge Adjustment (SECA) settlement reached in 2013. Through a series of orders issued by the FERC, Regional Through and Out Rates for transmission service between the MISO and the PJM Interconnection were eliminated effective December 1, 2004. To compensate transmission owners for the revenue they would no longer receive due to this rate elimination, the FERC ordered a transitional pricing mechanism called SECA be put into place. Integrys Energy Services protested the SECA order issued by the FERC. In 2013, Integrys Energy Services reached a settlement on all SECA issues and received a lump sum payment in complete settlement of the matters at issue. As a result, Integrys Energy Services recorded $5.7 million in other income in 2013 for the portion of the settlement not previously recognized.

2012 Compared with 2011

Revenues

Integrys Energy Services' revenues decreased $154.6 million, primarily driven by lower average commodity prices, partially offset by higher retail electric sales volumes.

Margins

Integrys Energy Services' margins increased $89.3 million. The significant items contributing to the change in margins were as follows:

Electric and Renewable Energy Asset Margins

Realized retail electric margins

Realized retail electric margins decreased $7.2 million. The decrease was driven by the expiration of several large customer contracts in the Illinois market at the end of 2011. Continued competitive pressure on per-unit margins also contributed to the decrease in margins. These decreases were partially offset by higher sales volumes due to aggregated customer participation in Illinois, as well as higher sales volumes in the New York, Mid-Atlantic, New England, and Michigan markets.

Realized renewable energy asset margins

Realized renewable energy asset margins increased $2.8 million. The increase was driven by continued investment in solar energy projects.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $65.2 million increase in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $1.6 million. The decrease was primarily driven by warmer weather year over year.

Inventory accounting adjustments

Integrys Energy Services' physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $15.1 million increase in margins from inventory adjustments was driven by lower write-downs and a higher volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services' margins. Fair value adjustments caused a $19.9 million increase in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income (Loss)

Integrys Energy Services' operating income increased $91.7 million. The main driver of the increase was the $89.3 million increase in margins discussed above. In addition, operating expenses decreased $2.4 million, driven by:

- A $4.6 million impairment loss recorded on a generation facility in 2011.

- A $3.2 million decrease in taxes other than income taxes.

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- A $3.0 million decrease in fees related to an intercompany credit agreement with the holding company.

These decreases were partially offset by:

- A $4.3 million increase in sales and marketing costs and outside service fees, primarily related to the expansion of the residential and small commercial customer business.

- A $4.0 million increase in bad debt expense, driven by the negative year over year impact of fewer recovery opportunities in 2012 compared with 2011.

Holding Company and Other Segment Operations

(Millions)	Year Ended December 31 2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Operating (loss) income	$(11.1)	$(6.0)	$5.7	85.0 %	N/A
Other expense	(28.2)	(29.1)	(34.0)	(3.1)%	(14.4)%
Loss before taxes	$(39.3)	$(35.1)	$(28.3)	12.0 %	24.0 %

2013 Compared with 2012

Operating Loss

Operating loss at the holding company and other segment increased $5.1 million. Included in this amount is a $2.0 million increase in operating losses at ITF, as well as miscellaneous items at the holding company.

Other Expense

Other expense at the holding company and other segment decreased $0.9 million. The decrease was driven by $4.0 million of excise tax credits recorded at ITF in 2013 as a result of the American Taxpayer Relief Act of 2012, partially offset by a $2.1 million increase in interest expense, driven by the issuance of $400.0 million of Junior Subordinated Notes during August 2013. See Note 12, Long-Term Debt, for more information.

2012 Compared with 2011

Operating Loss

Operating income at the holding company and other segment decreased $11.7 million to an operating loss in 2012. The decrease was driven partially by operating losses at ITF. In addition, the holding company charged Integrys Energy Services $3.0 million less for fees related to decreased use of an intercompany credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $4.9 million in 2012. Interest expense on long-term debt decreased, driven by lower average outstanding long-term debt in 2012. The year-over-year impact of impairments recorded on an investment in 2011 also contributed to the decrease.

Provision for Income Taxes

	Year Ended December 31 2013	2012	2011

Effective Tax Rate	37.6 %	33.8 %	36.7 %

2013 Compared with 2012

Our effective tax rate increased in 2013. In the fourth quarter of 2012, we elected to claim and subsequently received a Section 1603 Grant for WPS's Crane Creek wind project in lieu of production tax credits (PTCs). As a result, we no longer claim wind PTCs on any of our qualifying facilities. In 2012, our effective tax rate was also lowered by the effective settlement of certain state income tax examinations and remeasurements of uncertain tax positions included in our liability for unrecognized tax benefits. We decreased our provision for income taxes by $8.1 million in 2012, primarily related to these items. We also decreased our provision for income taxes by $5.9 million in 2012 as a result of WPS's 2013 rate case settlement agreement. WPS recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. See Note 26, Regulatory Environment, for more information.

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The increase in the effective tax rate was partially offset by a $3.7 million reduction in the provision for income taxes in 2013 due to the reversal of a regulatory liability. Deferred income taxes that had been recorded in prior years were reversed as a result of the treatment of scheduled income tax rate changes in Illinois in our final 2013 rate order.

2012 Compared with 2011

Our effective tax rate decreased in 2012. As discussed above, we decreased our provision for income taxes by $8.1 million in 2012 primarily due to the effective settlement of certain state income tax examinations and remeasurement of uncertain tax positions. We also decreased our provision for income taxes by $5.9 million in 2012 as a result of WPS's 2013 rate case settlement agreement as discussed above.

In 2011, we reduced our provision for income taxes by $5.8 million as a result of the 2012 rate orders for PGL and NSG. PGL and NSG recorded a regulatory asset after the rate order authorized recovery of deferred income taxes expensed in previous years also in connection with the 2010 federal health care reform. In addition, we increased our state income tax obligations in 2011, driven by tax law changes in Michigan and Wisconsin. We increased the provision for income taxes by $6.0 million in 2011 when we increased our deferred income tax liabilities related to these tax law changes.

For information on changes in the deferred income tax balances, see Note 14, Income Taxes.

Discontinued Operations

	Year Ended December 31			Change in	Change in
(Millions)	2013	2012	2011	2013 Over 2012	2012 Over 2011
Discontinued operations, net of tax	$4.8	$(9.7)	$0.5	N/A	N/A

2013 Compared with 2012

Earnings from discontinued operations, net of tax, increased $14.5 million in 2013. In 2012, Integrys Energy Services recognized after tax losses from discontinued operations of $6.9 million related to Westwood and $4.0 million related to Beaver Falls and Syracuse. Integrys Energy Services sold Westwood in November 2012 and Beaver Falls and Syracuse in March 2013. These losses were partially driven by the $5.7 million of after-tax impairment losses related to Westwood, Beaver Falls, and Syracuse recognized in 2012 when the generation facilities met the criteria for discontinued operations. See Note 4, Discontinued Operations, for more information.

In 2013, we remeasured uncertain tax positions included in our liability for unrecognized tax benefits at the holding company and other segment after effectively settling certain state income tax examinations. We reduced the provision for income taxes related to this remeasurement, of which the majority was reported as discontinued operations.

2012 Compared with 2011

Earnings from discontinued operations, net of tax, decreased $10.2 million in 2012. In 2012, Integrys Energy Services recognized $5.7 million of after tax impairment losses on generation facilities classified as held for sale that met the criteria for discontinued operations. See Note 4, Discontinued Operations, for more information. In addition, operating results at one of the generation facilities were negatively impacted when a long-term capacity contract expired in the fourth quarter of 2011. Discontinued operations decreased $3.8 million after tax related to this decrease in revenues.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

2013 Compared with 2012

During 2013, net cash provided by operating activities was $555.0 million, compared with $569.0 million during 2012. The $14.0 million decrease in net cash provided by operating activities was driven by:

- A $74.9 million increase in cash used to purchase natural gas that was injected into storage. The increase was driven by higher natural gas prices in 2013.

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- A $50.0 million payment in 2013 for WPS's early termination of a tolling agreement in connection with the purchase of Fox Energy Company LLC.

- A $42.8 million decrease in cash received from income taxes, primarily driven by a federal income tax refund received in 2012 for a net operating loss incurred in 2010 that was carried back to a prior year. The 2010 net operating loss was driven by bonus depreciation.

- A $34.3 million decrease in cash related to customer prepayments and credit balances due to higher natural gas prices and higher sales volumes in 2013.

- A $24.2 million decrease in cash at PGL and NSG due to natural gas cost under-collection activity with customers in 2013 versus natural gas cost over-collection activity with customers in 2012. The year-over-year change was driven by higher natural gas prices and higher sales volumes in 2013.

- A $7.3 million decrease in cash year-over-year driven by lower collateral requirements in 2012 at Integrys Energy Services. Collateral requirements are based on forward positions with counterparties.

These decreases in cash were partially offset by:

- A $210.5 million decrease in contributions to pension and other postretirement benefit plans.

- A $9.5 million increase in cash from a settlement received by Integrys Energy Services related to certain Seams Elimination Charge Adjustment payments made in prior years to a transmission provider.

2012 Compared with 2011

During 2012, net cash provided by operating activities was $569.0 million, compared with $717.8 million during 2011. The $148.8 million decrease in net cash provided by operating activities was largely driven by a $156.0 million year-over-year increase in contributions to pension and other postretirement benefit plans.

Investing Cash Flows

2013 Compared with 2012

During 2013, net cash used for investing activities was $1,024.3 million, compared with $605.0 million during 2012. The $419.3 million increase in net cash used for investing activities was primarily due to $391.6 million of cash used in 2013 for WPS's purchase of Fox Energy Company LLC. Integrys Energy Services also purchased Compass Energy Services, which increased net cash used for investing activities by $15.7 million. See Note 3, Acquisitions, for more information regarding these purchases. Also contributing to the increase was a $74.9 million increase in cash used to fund other capital expenditures (discussed below). These increases in net cash used were partially offset by the receipt of a $69.0 million Section 1603 Grant for WPS's Crane Creek wind project in 2013.

2012 Compared with 2011

During 2012, net cash used for investing activities was $605.0 million, compared with $393.5 million during 2011. The $211.5 million increase in net cash used for investing activities was primarily driven by a $284.2 million increase in cash used to fund capital expenditures (discussed below). Partially offsetting the increase in capital expenditures was a $43.9 million year-over-year impact related to the acquisition of the compressed natural gas fueling businesses in 2011.

Capital Expenditures

Capital expenditures by business segment for the year ended December 31 were as follows:

Reportable Segment (millions)	2013	2012	2011	Change in 2013 Over 2012	Change in 2012 Over 2011
Natural gas utility	$370.0	$375.1	$199.3	$(5.1)	$175.8
Electric utility	615.0	163.9	84.1	451.1	79.8
Integrys Energy Services	15.8	30.9	16.7	(15.1)	14.2
Holding company and other	60.0	24.4	10.0	35.6	14.4
Integrys Energy Group consolidated	$1,060.8	$594.3	$310.1	$466.5	$284.2

The increase in capital expenditures at the electric utility segment in 2013 compared with 2012 was primarily due to WPS's purchase of Fox Energy Company LLC in 2013. Capital expenditures at the electric utility segment also increased related to WPS's ReACT™ project at Weston 3. The

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decrease in capital expenditures at the Integrys Energy Services segment was primarily a result of decreased solar investments. Finally, capital expenditures increased at the holding company and other segment, primarily due to increased software project expenditures.

The increase in capital expenditures at the natural gas utility segment in 2012 compared with 2011 was primarily a result of the AMRP at PGL. The increase in capital expenditures at the electric utility segment was driven by environmental compliance projects at the Columbia plant. The increase in capital expenditures at the Integrys Energy Services segment was primarily a result of increased solar investments. Finally, capital expenditures increased at the holding company and other segment, primarily due to increased software project expenditures.

Financing Cash Flows

2013 Compared with 2012

During 2013, net cash provided by financing activities was $462.7 million, compared with $55.1 million during 2012. The $407.6 million increase in cash provided by financing activities was driven by:

- A $660.7 million net increase in cash due to a $746.0 million increase in the issuance of long-term debt, which was partially offset by a $85.3 million increase in the repayment of long-term debt. The issuance of long-term debt in 2013 included replacing WPS's borrowing of $200.0 million under its term credit facility in 2013, among other things. The cash proceeds from the term credit facility were used to partially finance the acquisition of Fox Energy Company LLC.

- An $87.9 million decrease in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. We began issuing new shares to meet these obligations in February 2013.

These increases were partially offset by a $335.5 million decrease in cash from $156.4 million of net repayments of commercial paper in 2013, compared with $179.1 million of net borrowings in 2012.

2012 Compared with 2011

During 2012, net cash provided by financing activities was $55.1 million, compared with net cash used for financing activities of $478.1 million during 2011. The $533.2 million year-over-year positive impact related to financing activities was driven by:

- A $665.6 million positive impact due to $149.8 million of net issuances of long-term debt in 2012, compared with $515.8 million of net repayments of long-term debt in 2011.

- A $45.5 million increase in cash received from stock option exercises.

- Partially offsetting these positive impacts were:

A $124.2 million decrease in net borrowings of commercial paper.

A $72.9 million increase in cash used to purchase shares of our common stock on the open market to satisfy requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans.

Significant Financing Activities

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

Period	Method of meeting requirements
Beginning 02/05/2014 [1]	Purchasing shares on the open market
02/05/2013 – 02/05/2014	Issued new shares
01/01/2012 – 02/04/2013	Purchased shares on the open market
01/01/2011 – 04/30/2011	Issued new shares

(1) The decision was made in conjunction with the announcement of the proposed sale of UPPCO. See Note 29, Subsequent Event, for more information.

For information on short-term debt, see Note 11, Short-Term Debt and Lines of Credit.

For information on the issuance and redemption of long-term debt in 2013, see Note 12, Long-Term Debt.

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Credit Ratings

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

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

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

On February 15, 2013, Standard & Poor's raised PGL's senior secured debt rating to "A" from "A-." PGL's revised rating reflects Standard & Poor's revision to its method for assigning recovery ratings for senior bonds secured by utility real property.

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

Discontinued Operations

These cash flows primarily relate to the operations of WPS Beaver Falls Generation, LLC, WPS Syracuse Generation, LLC, and Combined Locks Energy Center, LLC. The 2012 and 2011 cash flows also include the operations of WPS Westwood Generation, LLC. See Item 2 - Management's Discussion and Analysis of Financial Condition and Results of Operations – Discontinued Operations and Note 4, Discontinued Operations for more information.

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Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2013, including those of our subsidiaries:

		Payments Due By Period			
(Millions)	Total Amounts Committed	2014	2015 to 2016	2017 to 2018	2019 and Later Years
Long-term debt principal and interest payments [1]	$ 7,359.1	$246.7	$506.0	$382.1	$6,224.3
Operating lease obligations	93.6	6.7	12.8	14.7	59.4
Energy and transportation purchase obligations [2]	2,415.6	800.9	627.7	268.1	718.9
Purchase orders [3]	909.0	770.2	125.1	3.5	10.2
Capital contributions to equity method investment	5.1	5.1	—	—	—
Pension and other postretirement funding obligations [4]	506.8	84.2	92.6	60.0	270.0
Total contractual cash obligations	$ 11,289.2	$1,913.8	$1,364.2	$728.4	$7,282.8

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

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

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2018.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $599.7 million at December 31, 2013, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 15, Commitments and Contingencies, for more information about environmental liabilities. The table also does not reflect estimated future payments for the December 31, 2013 liability of $2.5 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 14, Income Taxes, for more information about unrecognized tax benefits.

Capital Requirements

As of December 31, 2013, our projected capital expenditures by segment for 2014 through 2016 were as follows:

(Millions)	2014	2015	2016	Total
Natural Gas Utility				
Distribution projects and underground storage facilities	$557	$476	$481	$1,514
Other projects	30	34	23	87

Electric Utility [1]				
Distribution and energy supply operations projects	139	137	131	407
Environmental projects [2]	140	135	105	380
Other projects	18	21	167	206
Integrys Energy Services				
Renewable energy and other projects	68	42	42	152
Holding Company and Other				
Corporate or shared services software and infrastructure projects	68	31	40	139
Compressed natural gas fueling stations	32	44	45	121
Repairs and safety measures at nonutility hydroelectric facilities [1]	—	—	1	1
Total capital expenditures	$1,052	$920	$1,035	$3,007

(1) Approximately $31 million of projected capital expenditures relates to UPPCO. See Note 29, Subsequent Event, for more information on the pending sale of UPPCO.

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

We expect to provide capital contributions to ATC (not included in the above table) of approximately $65 million from 2014 through 2016.

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

Capital Resources

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

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

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

At December 31, 2013, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 11, Short-Term Debt and Lines of Credit, for more information on credit facilities and other short-term credit agreements. See Note 12, Long-Term Debt, for more information on long-term debt.

Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. Our regulated utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 19, Common Equity, for more information on dividend restrictions.

Other Future Considerations

Decoupling

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

See Note 26, Regulatory Environment, for more information on all of our subsidiaries' decoupling mechanisms.

Climate Change

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

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

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

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

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

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

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

Tax Law Changes

In January 2013, President Obama signed into law the American Taxpayer Relief Act of 2012. This Act extended 50% bonus tax depreciation through 2013 for most capital expenditures. This bonus tax depreciation extension is anticipated to generate future cash flows in excess of $75 million through 2015.

In June 2013, Governor Walker signed into law a three-year budget bill, 2013 Wisconsin Act 20, which became effective January 1, 2014. Among other provisions, this Act conformed the Wisconsin tax code to the federal tax code with respect to tax depreciation and basis differences. This tax law change will accelerate the generation of future cash flows in excess of $15 million over a five-year amortization period through 2018.

In September 2013, the IRS issued tangible property regulations. In January 2014, the IRS issued general guidance on the implementation of the regulations and specific guidance related to certain types of public utility property. These regulations are broad and affect a multitude of items. The most substantial area of the regulations is determining if an expenditure related to tangible property is a repair or should be capitalized. In recent years, our utilities filed changes in the method of accounting related to repairs of public utility property. We believe the previously filed method changes are materially consistent with the regulations as issued. Therefore, the issuance of the regulations is not expected to have a material effect on our financial position.

Qualifying Infrastructure Plant (QIP) Rider

In July 2013, Illinois Public Act 98-0057 (formerly Senate Bill 2266), The Natural Gas Consumer, Safety & Reliability Act, became law. The Act gives certain natural gas utilities, including PGL, a cost recovery mechanism for Illinois natural gas infrastructure upgrades that will be collected through a surcharge on customer bills. Later in July 2013, the ICC adopted emergency rules to implement the law, and in December 2013, the ICC issued an order to adopt permanent rules, replacing the emergency rules. This Act eliminated a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation. In September 2013, PGL filed with the ICC requesting the proposed rider, and the ICC approved the tariff in January 2014. The rider became effective on January 1, 2014.

OFF BALANCE SHEET ARRANGEMENTS

See Note 16, Guarantees for information regarding guarantees.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We have determined that the following accounting policies and estimates are critical to the understanding of our financial statements because their application requires significant judgment and reliance on estimations of matters that are inherently uncertain. Our management has discussed these critical accounting policies and estimates with the Audit Committee of the Board of Directors.

Risk Management Activities

We have entered into contracts that are accounted for as derivatives. All derivative contracts are recorded at fair value on the balance sheets, unless they qualify for the normal purchases and sales exception, which provides that recognition of gains and losses in the financial statements is not required until the settlement of the contracts. Changes in fair value, except for those qualifying for regulatory deferral, generally affect net income attributed to common shareholders at each financial reporting date until the contracts are ultimately settled.

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We have based our valuations on observable inputs whenever possible. However, at times, the valuation of certain derivative instruments requires the use of internally developed valuation techniques and/or significant unobservable inputs. These valuations require a significant amount of management judgment and are classified as Level 3 measurements in the fair value hierarchy. Of the total risk management assets on our balance sheet at December 31, 2013, $53.8 million (17.1%) were classified as Level 3 measurements. Of the total risk management liabilities, $31.7 million (14.0%) were classified as Level 3 measurements. We believe these valuations represent the fair values of these instruments as of the reporting date; however, the actual amounts realized upon settlement of these instruments could vary materially from the reported amounts due to movements in market prices and changes in the liquidity of certain markets.

As a component of fair value determinations, we consider counterparty credit risk and our own credit risk. Changes in the underlying assumptions for the credit risk component of fair value at December 31, 2013, would have had the following effects:

Change in Risk Components (Millions)	Effect on Fair Value of Net Risk Management Assets
100% increase	$1.5 decrease
50% decrease	$0.7 increase

These hypothetical changes in fair value would impact current and long-term assets and liabilities from risk management activities on the balance sheets and nonregulated revenues on the income statements.

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2013. No impairment was recorded as a result of these tests. See Note 9, Goodwill and Other Intangible Assets, for our goodwill balances by segment. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. The fair value was calculated using an equal weighting of the income approach and the market approach.

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

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

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

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

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

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The fair values calculated in the first step of the test for MERC, MGU, NSG, and PGL exceeded the carrying values by approximately 3%-19%. Due to the subjectivity of the assumptions and estimates underlying the impairment analyses, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, which would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test. Failing step one would result in a goodwill impairment that could be material, as the carrying value of the identifiable assets and liabilities is considered fair value for regulated companies. Any difference between the fair value and carrying value of the reporting unit would be recorded as a goodwill impairment. Carrying value is considered fair value for regulated companies because a regulator would typically not allow the assets and liabilities of a regulated company to be increased or decreased, allowing for a change in recovery from ratepayers, as a result of an acquisition or other change in ownership.

Change in Key Inputs (in basis points)	MERC	MGU	NSG	PGL
Discount rate	30	20	280	120
Terminal year return on equity	(220)	(180)	(535)	(387)
Terminal year growth rate	(25)	(25)	N/A *	(125)

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

Accrued Unbilled Revenues

We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. Significant changes in these judgments and assumptions could have a material impact on our results of operations. At WPS, the use of Automated Meter Reading technology has greatly reduced the judgments and assumptions required related to weather and customer use. At December 31, 2013, and 2012, our unbilled revenues were $438.2 million and $298.2 million, respectively. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer use patterns, commodity prices, and customer mix.

Pension and Other Postretirement Benefits

The costs of providing noncontributory defined benefit pension benefits and other postretirement benefits, described in Note 17, Employee Benefit Plans, are dependent on numerous factors resulting from actual plan experience and assumptions regarding future experience.

Pension and other postretirement benefit costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and other postretirement benefit costs may be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and other postretirement benefit costs.

Pension and other postretirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered/refunded at the regulated utility segments through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (Millions, except percentages)	Percentage-Point Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2013 Pension Cost
Discount rate	(0.5)	$116.1	$10.7
Discount rate	0.5	(97.7)	(8.6)
Rate of return on plan assets	(0.5)	N/A	6.6
Rate of return on plan assets	0.5	N/A	(6.6)

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The following table shows how a given change in certain actuarial assumptions would impact the accumulated other postretirement benefit obligation and the reported net periodic other postretirement benefit cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (Millions, except percentages)	Percentage-Point Change in Assumption	Impact on Postretirement Benefit Obligation	Impact on 2013 Postretirement Benefit Cost
Discount rate	(0.5)	$38.1	$3.6
Discount rate	0.5	(35.6)	(3.0)
Health care cost trend rate	(1.0)	(65.5)	(10.3)
Health care cost trend rate	1.0	80.6	13.3
Rate of return on plan assets	(0.5)	N/A	1.9
Rate of return on plan assets	0.5	N/A	(1.9)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds with maturities between 0 and 30 years. The bonds are generally rated "Aa" with a minimum amount outstanding of $50.0 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on asset assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return was 8.00% in 2013 and 8.25% in both 2012 and 2011. The actual rates of return on pension plan assets, net of fees, were 15.1%, 14.3%, and 1.5%, in 2013, 2012, and 2011, respectively.

The determination of expected return on qualified plan assets is based on a market-related valuation of assets, which reduces year-to-year volatility. Cumulative gains and losses in excess of 10% of the greater of the pension or other postretirement benefit obligation or market-related value are amortized over the average remaining future service to expected retirement ages. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by WPS. However, for plans sponsored by IBS and PELLC, only differences between actual investment returns and the expected returns on plan assets are recognized over a five-year period. Under this method, the future value of assets is impacted as previously deferred gains or losses are included in market-related value.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and other postretirement benefits, see Note 17, Employee Benefit Plans.

Regulatory Accounting

Our natural gas and electric utility segments follow the guidance under the Regulated Operations Topic of the FASB ASC. Our financial statements reflect the effects of the ratemaking principles followed by the various jurisdictions regulating these segments. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery period. If recovery or refund of costs is not approved or is no longer deemed probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, earnings at the natural gas and electric utility segments, and the status of any pending or potential deregulation legislation.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our natural gas and electric utility segments' operations no longer meet the criteria for application. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2013, would result in a 13.7% decrease in total assets and a 6.3% decrease in total liabilities. The two largest regulatory assets at December 31, 2013, related to environmental remediation costs and unrecognized pension and other postretirement benefit costs. A write-off of the regulatory asset related to environmental remediation costs at December 31, 2013, would result in a 5.8% decrease in total assets. A write-off of the unrecognized pension and other postretirement benefit related regulatory asset at December 31, 2013, would result in a 3.8% decrease in total assets See Note 7, Regulatory Assets and Liabilities, for more information.

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Income Tax Provision

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to the provision for income taxes in the income statements.

Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(q), Income Taxes, and Note 14, Income Taxes, for a discussion of accounting for income taxes.

IMPACT OF INFLATION

Our financial statements are prepared in accordance with GAAP. The statements provide a reasonable, objective, and quantifiable picture of financial results, but generally do not evaluate the impact of inflation. To the extent our regulated operations are not recovering the effects of inflation, they will file rate cases as necessary in the various jurisdictions in which they operate. Our nonregulated businesses include inflation in forecasted costs, which impacts product pricing.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

Utility Segments

Prudent fuel and purchased power costs and capacity payments are recovered from customers under one-for-one recovery mechanisms by UPPCO, and by the wholesale electric operations and Michigan retail electric operations of WPS. Prudently incurred costs of natural gas used by the natural gas utilities are also recovered from customers under one-for-one recovery mechanisms. These recovery mechanisms greatly reduce commodity price risk for the utilities.

WPS's Wisconsin retail electric operations do not have a one-for-one recovery mechanism for price fluctuations. Instead, a "fuel window" mechanism substantially mitigates this price risk. See Note 1(e), Revenue and Customer Receivables, for more information.

To manage commodity price risk for their customers, the regulated utilities enter into fixed-price contracts of various durations for the purchase and/or sale of natural gas, fuel for electric generation, and electricity. They also employ risk management techniques, which include the use of derivative instruments such as swaps, futures, and options.

Nonregulated Segments

Integrys Energy Services seeks to reduce market price risk from its generation and energy supply portfolios through the use of various financial and physical instruments. Additionally, Integrys Energy Services uses volume limits and stop loss limits as defined in its Risk Policy to limit its exposure to commodity price movements.

To measure commodity price risk exposure, Integrys Energy Services employs a number of controls and processes, including a value-at-risk (VaR) analysis of its exposures. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors, within a given confidence level, if an instrument or portfolio is held for a specified time period. The VaR calculation is used to quantify exposure to market risk associated with open commodity positions (primarily natural gas and power positions).

The VaR calculation includes financial and physical commodity instruments, such as forwards, futures, swaps, and options, as well as natural gas inventory, natural gas storage, and transportation contracts, to the extent such positions are significant. The VaR calculation excludes the positions created by owning energy assets and associated renewable energy credits, and other ancillary fuels. Additionally, financial transmission rights, certain electric ancillary services, and certain portions of long-dated natural gas storage and transportation contracts are also excluded from the VaR calculation. VaR is calculated using nondiscounted positions with a delta-normal approximation based on a ten-day holding period and a 99% confidence level.

The VaR model is not intended to represent actual losses in fair value that we expect to incur, but is used as a risk estimation and management tool.

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

(Millions)	2013	2012
As of December 31	$1.2	$0.6
Average for 12 months ended December 31	0.9	0.5
High for 12 months ended December 31	1.2	0.7
Low for 12 months ended December 31	0.6	0.4

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

Interest Rate Risk

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

Based on the variable rate debt outstanding at December 31, 2013, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.3 million. Comparatively, based on the variable rate debt outstanding at December 31, 2012, an increase in

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interest rates of 100 basis points would have increased annual interest expense by $4.8 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Equity Return and Principal Preservation Risk

We currently fund liabilities related to employee benefits through various external trust funds. The trust funds are managed by numerous investment managers and primarily hold investments in debt and equity securities. Changes in the market value of these investments can have an impact on the future expenses related to these liabilities. Declines in the equity markets or declines in interest rates may result in increased future costs for the plans and require additional contributions into the plans. We monitor the trust fund portfolio by benchmarking the performance of the investments against certain security indices. Most of our employee benefit costs relate to the regulated utilities. As such, the majority of these costs are recovered in customers' rates, reducing most of the equity return and principal preservation risk on these exposures. Also, the likelihood of an increase in the employee benefit obligations, which the investments must fund, has been partially mitigated as a result of certain employee groups no longer being eligible to participate in, or accumulate benefits in, certain pension and other postretirement benefit plans. Our defined benefit pension plans are closed to all new hires, and the service accruals for the defined benefit pension plans are frozen for non-union employees as of January 1, 2013.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Integrys Energy Group and our subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting. Our control systems were designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2013. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (1992). Based on this assessment, management believes that, as of December 31, 2013, our internal control over financial reporting is effective.

Our independent registered public accounting firm has issued an audit report on the effectiveness of our internal control over financial reporting.

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B. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Integrys Energy Group, Inc.:
We have audited the internal control over financial reporting of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2013, of the Company and our report dated February 27, 2014, expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
February 27, 2014

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C. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 (Millions, except per share data)	2013	2012	2011
Utility revenues	$3,425.6	$2,959.5	$3,294.5
Nonregulated revenues	2,209.0	1,252.9	1,391.4
Total revenues	5,634.6	4,212.4	4,685.9
Utility cost of fuel, natural gas, and purchased power	1,570.4	1,326.3	1,635.3
Nonregulated cost of sales	1,937.2	1,040.2	1,274.2
Operating and maintenance expense	1,192.3	1,031.3	1,024.8
Depreciation and amortization expense	266.6	250.7	247.7
Taxes other than income taxes	100.4	96.4	97.1
Operating income	567.7	467.5	406.8
Earnings from equity method investments	91.5	87.2	79.4
Miscellaneous income	29.8	9.3	5.3
Interest expense	128.2	120.2	128.2
Other expense	(6.9)	(23.7)	(43.5)
Income before taxes	560.8	443.8	363.3
Provision for income taxes	210.8	149.8	133.3
Net income from continuing operations	350.0	294.0	230.0
Discontinued operations, net of tax	4.8	(9.7)	0.5
Net income	354.8	284.3	230.5
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.2	—
Net income attributed to common shareholders	$351.8	$281.4	$227.4
Average shares of common stock			
Basic	79.5	78.6	78.6
Diluted	80.1	79.3	79.1
Earnings (loss) per common share (basic)			
Net income from continuing operations	$4.37	$3.70	$2.89
Discontinued operations, net of tax	0.06	(0.12)	—
Earnings per common share (basic)	$4.43	$3.58	$2.89
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$4.33	$3.67	$2.87
Discontinued operations, net of tax	0.06	(0.12)	—
Earnings per common share (diluted)	$4.39	$3.55	$2.87

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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D. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31			
(Millions)	2013	2012	2011
Net income	$354.8	$284.3	$230.5
Other comprehensive income, net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of $0.1 million, $(0.1) million, and $0.4 million, respectively	0.7	(0.2)	1.5
Reclassification of net losses to net income, net of tax of $3.6 million, $2.0 million, and $4.4 million, respectively	1.4	6.5	7.4
Cash flow hedges, net	2.1	6.3	8.9
Defined benefit plans			
Pension and other postretirement benefit adjustments arising during period, net of tax of $8.9 million, $(4.4) million, and $(5.7) million, respectively	13.2	(6.1)	(7.5)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $1.7 million, $1.0 million, and $0.6 million, respectively	2.4	1.4	0.8
Defined benefit plans, net	15.6	(4.7)	(6.7)
Other comprehensive income, net of tax	17.7	1.6	2.2
Comprehensive income	372.5	285.9	232.7
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.2	—
Comprehensive income attributed to common shareholders	$369.5	$283.0	$229.6

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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E. CONSOLIDATED BALANCE SHEETS

At December 31 (Millions)	2013	2012
Assets		
Cash and cash equivalents	$22.3	$27.4
Collateral on deposit	38.7	41.0
Accounts receivable and accrued unbilled revenues, net of reserves of $49.8 and $43.5, respectively	1,052.1	796.8
Inventories	254.8	271.9
Assets from risk management activities	240.1	145.4
Regulatory assets	129.4	110.8
Assets held for sale	0.7	10.1
Deferred income taxes	31.4	64.3
Prepaid taxes	146.9	152.8
Other current assets	55.8	38.6
Current assets	1,972.2	1,659.1
Property, plant, and equipment, net of accumulated depreciation of $3,325.8 and $3,114.7, respectively	6,410.5	5,501.9
Regulatory assets	1,412.6	1,813.8
Assets from risk management activities	75.4	45.3
Equity method investments	540.9	512.2
Goodwill	662.1	658.3
Other long-term assets	169.8	136.8
Total assets	$11,243.5	$10,327.4
Liabilities and Equity		
Short-term debt	$326.0	$482.4
Current portion of long-term debt	100.0	313.5
Accounts payable	613.2	457.7
Liabilities from risk management activities	163.8	181.9
Accrued taxes	86.3	83.0
Regulatory liabilities	101.5	65.6
Liabilities held for sale	—	0.2
Other current liabilities	231.3	229.0
Current liabilities	1,622.1	1,813.3
Long-term debt	2,956.2	1,931.7
Deferred income taxes	1,390.3	1,203.8
Deferred investment tax credits	57.6	49.3
Regulatory liabilities	400.9	370.5
Environmental remediation liabilities	600.8	651.5
Pension and other postretirement benefit obligations	211.0	625.2
Liabilities from risk management activities	62.8	58.4
Asset retirement obligations	491.5	411.2
Other long-term liabilities	136.9	135.7
Long-term liabilities	6,308.0	5,437.3

Commitments and contingencies		
Common stock – $1 par value; 200,000,000 shares authorized; 79,919,176 shares issued; 79,445,380 shares outstanding	79.9	78.3
Additional paid-in capital	2,660.5	2,574.6
Retained earnings	567.1	431.5
Accumulated other comprehensive loss	(23.2)	(40.9)
Shares in deferred compensation trust	(23.0)	(17.7)
Total common shareholders' equity	3,261.3	3,025.8
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	1.0	(0.1)
Total liabilities and equity	$11,243.5	$10,327.4

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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F. CONSOLIDATED STATEMENTS OF EQUITY

(Millions)	Integrys Energy Group Common Shareholders' Equity								
	Shares in Deferred Compensation Trust	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Noncontrolling Interest in Subsidiaries	Total Equity
Balance at December 31, 2010	$(18.5)	$77.8	$2,540.4	$350.8	$ (44.7)	$ 2,905.8	$ 51.1	$ 0.1	$2,957.0
Net income attributed to common shareholders	—	—	—	227.4	—	227.4	—	—	227.4
Other comprehensive income	—	—	—	—	2.2	2.2	—	—	2.2
Issuance of common stock	—	0.5	21.7	—	—	22.2	—	—	22.2
Stock-based compensation	—	—	7.5	(2.1)	—	5.4	—	—	5.4
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(211.8)	—	(211.8)	—	—	(211.8)
Shares issued to and purchased for the deferred compensation trust	(3.3)	—	2.3	—	—	(1.0)	—	—	(1.0)
Other	4.7	—	7.2	(0.7)	—	11.2	—	—	11.2
Balance at December 31, 2011	$(17.1)	$78.3	$2,579.1	$363.6	$ (42.5)	$ 2,961.4	$ 51.1	$ 0.1	$3,012.6
Net income attributed to common shareholders	—	—	—	281.4	—	281.4	—	(0.2)	281.2
Other comprehensive income	—	—	—	—	1.6	1.6	—	—	1.6
Issuance of common stock	—	—	—	—	—	—	—	—	—
Stock-based compensation	—	—	(4.1)	(0.7)	—	(4.8)	—	—	(4.8)
Dividends on common stock	—	—	—	(211.9)	—	(211.9)	—	—	(211.9)

(dividends per common share of $2.72)									
Shares purchased for the deferred compensation trust	(3.2)	—	—	—	—	(3.2)	—	—	(3.2)
Other	2.6	—	(0.4)	(0.9)	—	1.3	—	—	1.3
Balance at December 31, 2012	$(17.7)	$78.3	$2,574.6	$431.5	$ (40.9)	$ 3,025.8	$ 51.1	$ (0.1)	$3,076.8
Net income attributed to common shareholders	—	—	—	351.8	—	351.8	—	(0.1)	351.7
Other comprehensive income	—	—	—	—	17.7	17.7	—	—	17.7
Issuance of common stock	—	1.5	78.3	—	—	79.8	—	—	79.8
Stock-based compensation	—	—	1.0	(0.7)	—	0.3	—	—	0.3
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(214.6)	—	(214.6)	—	—	(214.6)
Net contributions from noncontrolling parties	—	—	—	—	—	—	—	1.0	1.0
Shares issued to the deferred compensation trust	(6.3)	0.1	6.2	—	—	—	—	—	—
Other	1.0	—	0.4	(0.9)	—	0.5	—	0.2	0.7
Balance at December 31, 2013	$(23.0)	$79.9	$2,660.5	$567.1	$ (23.2)	$ 3,261.3	$ 51.1	$ 1.0	$3,313.4

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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G. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31			
(Millions)	2013	2012	2011
Operating Activities			
Net income	$354.8	$284.3	$230.5
Adjustments to reconcile net income to net cash provided by operating activities			
Discontinued operations, net of tax	(4.8)	9.7	(0.5)
Depreciation and amortization expense	266.6	250.7	247.7
Recoveries and refunds of regulatory assets and liabilities	44.3	49.9	56.1
Net unrealized (gains) losses on energy contracts	(102.2)	(40.3)	45.2
Bad debt expense	34.4	26.2	35.0
Pension and other postretirement expense	62.1	62.1	59.9
Pension and other postretirement contributions	(77.0)	(287.5)	(131.5)
Deferred income taxes and investment tax credits	198.5	148.2	174.1
Equity income, net of dividends	(19.2)	(17.5)	(14.8)
Termination of tolling agreement with Fox Energy Company LLC	(50.0)	—	—
Other	41.0	20.1	45.9
Changes in working capital			
Collateral on deposit	2.3	9.6	(17.3)
Accounts receivable and accrued unbilled revenues	(358.8)	(26.2)	93.4
Inventories	16.8	28.5	(37.1)
Other current assets	(42.0)	6.1	55.3
Accounts payable	143.1	22.0	(37.3)
Other current liabilities	45.1	23.1	(86.8)
Net cash provided by operating activities	555.0	569.0	717.8
Investing Activities			
Capital expenditures	(669.2)	(594.3)	(310.1)
Capital contributions to equity method investments	(13.7)	(27.4)	(37.6)
Acquisition of Fox Energy Company LLC	(391.6)	—	—
Acquisitions at Integrys Energy Services	(15.7)	—	—
Grant received related to Crane Creek wind project	69.0	—	—
Acquisition of compressed natural gas fueling companies, net of cash acquired	—	1.3	(42.6)
Other	(3.1)	15.4	(3.2)
Net cash used for investing activities	(1,024.3)	(605.0)	(393.5)
Financing Activities			
Short-term debt, net	(156.4)	179.1	303.3
Repayment of notes payable	—	—	(10.0)
Borrowing on term credit facility	200.0	—	—
Repayment of term credit facility	(200.0)	—	—
Issuance of long-term debt	1,174.0	428.0	50.0
Repayment of long-term debt	(363.5)	(278.2)	(565.8)
Proceeds from stock option exercises	38.7	55.8	10.3
Shares purchased for stock-based compensation	(2.0)	(89.9)	(17.0)
Payment of dividends			
Preferred stock of subsidiary	(3.1)	(3.1)	(3.1)
Common stock	(202.6)	(211.9)	(206.4)
	(5.8)	(23.7)	(31.9)

Payments made on derivative contracts related to divestitures classified as financing activities			
Other	(16.6)	(1.0)	(7.5)
Net cash provided by (used for) financing activities	462.7	55.1	(478.1)
Change in cash and cash equivalents – continuing operations	(6.6)	19.1	(153.8)
Change in cash and cash equivalents – discontinued operations			
Net cash (used for) provided by operating activities	(0.1)	4.8	4.1
Net cash provided by (used for) investing activities	1.6	2.4	(0.9)
Net cash used for financing activities	—	(27.0)	(0.3)
Net change in cash and cash equivalents	(5.1)	(0.7)	(150.9)
Cash and cash equivalents at beginning of year	27.4	28.1	179.0
Cash and cash equivalents at end of year	$22.3	$27.4	$28.1
Cash paid for interest	$116.1	$109.7	$130.7
Cash received for income taxes	(4.8)	(47.6)	(80.0)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

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H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Summary of Significant Accounting Policies

(a) Nature of Operations—We are a holding company whose primary wholly owned subsidiaries at December 31, 2013, included MERC, MGU, NSG, PGL, UPPCO, WPS, IBS, Integrys Energy Services, and ITF. Of these subsidiaries, six are regulated natural gas and/or electric utilities (MERC, MGU, NSG, PGL, UPPCO, and WPS). IBS is a centralized service company, Integrys Energy Services is a nonregulated retail energy supply and services company, and ITF is a nonregulated compressed natural gas fueling business. In addition, we have an approximate 34% interest in ATC.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the consolidated statements of income, consolidated statements of comprehensive income, consolidated balance sheets, consolidated statements of equity, and consolidated statements of cash flows, unless otherwise noted.

The term "utility" refers to the regulated activities of the electric and natural gas utility companies, while the term "nonutility" refers to the activities of the electric and natural gas utility companies that are not regulated. The term "nonregulated" refers to activities at Integrys Energy Services, ITF, the Integrys Energy Group holding company, and the PELLC holding company.

(b) Consolidated Basis of Presentation—The financial statements include our accounts and the accounts of all of our majority owned subsidiaries, after eliminating intercompany transactions and balances. These financial statements also reflect our proportionate interests in certain jointly owned utility facilities. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. Investments in businesses not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. See Note 8, Equity Method Investments, for more information.

(c) Use of Estimates—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect assets, liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(d) 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:

(Millions)	2013	2012	2011
Construction costs funded through accounts payable	$108.5	$92.4	$58.6
Portion of Westwood sale financed with note receivable [1]	—	4.0	—
Equity issued for stock-based compensation plans	16.3	—	10.6
Equity issued for employee stock ownership plan	14.3	—	5.2
Equity issued for reinvested dividends	12.0	—	5.4
Contingent consideration related to the acquisition of Compass Energy Services [2]	7.8	—	—

(1) See Note 4, Discontinued Operations, for more information.
(2) See Note 3, Acquisitions, for more information on the contingent consideration.

(e) Revenue and Customer Receivables—Revenues related to the sale of energy are recognized when service is provided or energy is delivered to customers. We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class, contracted rates, weather, and customer use. At December 31, 2013 and 2012, our unbilled revenues were $438.2 million and $298.2 million, respectively.

At December 31, 2013, there were no customers or industries that accounted for more than 10% of our revenues.

We present revenues net of pass-through taxes on the income statements.

Below is a summary of the significant mechanisms our utility subsidiaries had in place in 2013 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

- Fuel and purchased power costs were recovered from customers on a one-for-one basis by UPPCO, WPS's wholesale electric operations, and WPS's Michigan retail electric operations.
- WPS's Wisconsin retail electric operations used a "fuel window" mechanism to recover fuel and purchased power costs. Under the fuel window rule, a deferral is required for under or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers.
- The rates for all of our natural gas utilities included one-for-one recovery mechanisms for natural gas commodity costs.
- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup and energy conservation and management program costs.

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- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.
- The rates of PGL, NSG, and MGU included riders for cost recovery or refund of bad debts based on the difference between actual bad debt write-offs (as defined in the latest rate order) and the amount recovered in rates. MGU's rider was terminated after December 31, 2013.
- The rates of all of our utilities included decoupling mechanisms. These mechanisms differ state by state and allow utilities to recover or refund differences between the applicable actual and authorized margins. See Note 26, Regulatory Environment, for more information on decoupling.

Revenues are also impacted by other accounting policies related to PGL's natural gas hub and our electric utilities' participation in the MISO market. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. WPS and UPPCO both sell and purchase power in the MISO market. If WPS or UPPCO is a net seller in a particular hour, the net amount is reported as revenue. If WPS or UPPCO is a net purchaser in a particular hour, the net amount is recorded as utility cost of fuel, natural gas, and purchased power on the income statements.

ITF accounts for revenues from construction management projects using the percentage of completion method. Revenues are recognized based on the percentage of costs incurred to date compared to the total estimated costs of each contract. This method is used because management considers total costs to be the best available measure of progress on these contracts.

See Note 1(g), Risk Management Activities, for more information on the classification of certain unrealized gains and losses on derivative instruments in revenues.

(f) Inventories—Inventories consist of materials and supplies, natural gas in storage, liquid propane, emission allowances at WPS, and fossil fuels, including coal. Average cost is used to value materials and supplies, fossil fuels, liquid propane, emission allowances at WPS, and natural gas in storage for the regulated utilities, excluding PGL and NSG. PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the Last-in, First-out (LIFO) cost method. Inventories stated on a LIFO basis represented approximately 26% of total inventories at December 31, 2013, and 30% of total inventories at December 31, 2012. The estimated replacement cost of natural gas in inventory at December 31, 2013, and December 31, 2012, exceeded the LIFO cost by $151.7 million and $95.3 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per dekatherm of $4.77 at December 31, 2013, and $3.58 at December 31, 2012.

Inventories at Integrys Energy Services are valued at the lower of cost or market. As a result, Integrys Energy Services recorded net write-downs of $3.6 million, $3.4 million, and $11.6 million in 2013, 2012, and 2011, respectively.

(g) Risk Management Activities—As part of our regular operations, we enter into contracts, including options, swaps, futures, forwards, and other contractual commitments, to manage market risks such as changes in commodity prices and interest rates. See Note 2, Risk Management Activities, for more information. Derivative instruments are entered into in accordance with the terms of each subsidiary's risk management policies approved by their respective Boards of Directors and, if applicable, by their respective regulators.

All derivatives are recognized on the balance sheets at their fair value unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Because most energy-related derivatives at the utilities qualify for regulatory deferral, management believes any gains or losses resulting from the eventual settlement of derivative instruments will be refunded to or collected from customers in rates. As such, any changes in the fair value of these derivatives recorded as either risk management assets or liabilities are offset with regulatory liabilities or assets, as appropriate.

We classify derivative assets and liabilities as current or long-term on the balance sheets based on the maturities of the underlying contracts. We record unrealized gains and losses on derivative instruments that do not qualify for hedge accounting or regulatory deferral as a component of margins or operating and maintenance expense, depending on the nature of the transactions. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the statements of cash flows unless the derivative contracts contain an other-than-insignificant financing element, in which case the cash flows are classified within financing activities.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On the balance sheets, cash collateral provided to others is shown separately as collateral on deposit, and cash collateral received from others is reflected in other current liabilities.

(h) Emission Allowances—Integrys Energy Services accounts for emission allowances as intangible assets, with cash inflows and outflows related to purchases and sales of emission allowances recorded as investing activities in the statements of cash flows. WPS accounts for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating WPS's generation plants. These charges are included in the costs subject to the fuel window rules. Gains on sales of allowances at WPS are returned to ratepayers.

(i) Property, Plant, and Equipment—Utility plant is stated at cost, including any associated AFUDC and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses.

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The utilities record a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. Ordinary retirements, sales, and other disposals of units of property at the utilities are charged to accumulated depreciation at cost, less salvage value. When it becomes probable that an operating unit will be retired in the near future and substantially in advance of its expected useful life, the cost and corresponding accumulated depreciation of the asset is classified as plant to be retired, net within property, plant, and equipment.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	2013		2012		2011	
MERC [1]	1.88	%	3.07	%	3.10	%
MGU [2]	1.93	%	2.71	%	2.73	%
NSG	2.44	%	2.43	%	2.42	%
PGL	3.19	%	3.16	%	3.18	%
UPPCO	3.29	%	3.31	%	3.33	%
WPS – Electric	2.79	%	2.87	%	2.88	%
WPS – Natural gas	2.19	%	2.21	%	2.22	%

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

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

The majority of nonregulated plant is stated at cost, net of impairments recorded, and includes capitalized interest. The costs of renewals, betterments, and major overhauls are capitalized as additions to plant. Nonregulated plant acquired as a result of mergers and acquisitions have been recorded at fair value. The gains or losses associated with ordinary retirements are recorded in the period of retirement. Maintenance, repair, and minor replacement costs are expensed as incurred. Depreciation is computed for the majority of the nonregulated subsidiaries' assets using the straight-line method over the assets' useful lives.

We capitalize certain costs related to software developed or obtained for internal use and amortize those costs to operating expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

We receive grants related to certain renewable generation projects under federal and state grant programs. Our policy is to reduce the depreciable basis of the qualifying project by the grant received. We then reflect the benefit of the grant in income over the life of the related renewable generation project through a reduction in depreciation expense. See Note 5, Property, Plant, and Equipment, for more information.

(j) AFUDC and Capitalized Interest—Our utilities and IBS capitalize the cost of funds used for construction using a calculation that includes both internal equity and external debt components, as required by regulatory accounting. The internal equity component is accounted for as other income. The external debt component is accounted for as a decrease to interest expense.

The majority of AFUDC is recorded at WPS. Approximately 50% of WPS's retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. For 2013, WPS's average AFUDC retail rate was 8.61%, and its average AFUDC wholesale rate was 2.64%. The AFUDC calculation for the other utilities and IBS is determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities and IBS did not record significant AFUDC for 2013, 2012, or 2011.

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

	2013	2012	2011
Allowance for equity funds used during construction	$10.8	$2.9	$0.7
Allowance for borrowed funds used during construction	4.1	1.0	0.3

Our nonregulated subsidiaries capitalize interest for construction projects. However, the nonregulated subsidiaries did not capitalize significant interest during 2013, 2012, and 2011.

(k) Regulatory Assets and Liabilities—Regulatory assets represent probable future revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in rates for future costs. Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the year the determination is made. See Note 7, Regulatory Assets and Liabilities, for more information.

(l) Investments in Exchange-Traded Funds—We have investments in exchange-traded funds which are classified as trading securities for accounting purposes. These investments are used to offset gains and losses related to our deferred compensation obligations. As we do not intend to sell these investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains (losses) included in earnings related to the investments still held at the end of the period were $1.9 million, $1.0 million, and $(0.1) million for the years ended December 31, 2013, 2012, and 2011, respectively.

(m) Asset Impairment—Goodwill and other intangible assets with indefinite lives are not amortized, but are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 9, Goodwill and Other Intangible Assets, for more information on our goodwill and other intangible assets.

The carrying amount of tangible long-lived assets held and used is considered not recoverable if the carrying amount exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying amount over its fair value.

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

The carrying amounts of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

Integrys Energy Services evaluates emission allowances for impairment by comparing the expected undiscounted future cash flows to the carrying amount. When allowances are expected to be used for generation, the allowances are grouped with the related power plant in the impairment evaluation.

(n) Retirement of Debt—Any call premiums or unamortized expenses associated with refinancing utility debt obligations are amortized consistent with regulatory treatment of those items. Any gains or losses resulting from the retirement of utility debt that is not refinanced are amortized over the remaining life of the original debt. Any gains or losses resulting from the retirement of nonutility debt are recorded through current earnings.

(o) Asset Retirement Obligations—We recognize at fair value legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the liability and the associated retirement cost. See Note 13, Asset Retirement Obligations, for more information.

(p) Environmental Remediation Costs— We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party (PRP). Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including former manufactured gas plant sites. See Note 15, Commitments and Contingencies, for more information on our manufactured gas plant sites.

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

Our regulated utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the respective Commission's approval.

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We review our estimated costs of remediation annually for our manufactured gas plant sites and adjust the liabilities and related regulatory assets to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(q) Income Taxes—We file a consolidated United States income tax return that includes domestic subsidiaries of which our ownership is 80% or more. We and our consolidated subsidiaries are parties to a federal and state tax allocation arrangement under which each entity determines its provision for income taxes on a stand-alone basis. In several states, combined or consolidated filings are required for certain subsidiaries doing business in that state.

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

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

We report interest and penalties accrued related to income taxes as a component of provision for income taxes in the income statements, as well as regulatory assets or regulatory liabilities on the balance sheets.

We record excess tax benefits from stock-based compensation awards when the actual tax benefit is realized. We follow the tax law ordering approach to determine when the tax benefit has been realized. Under this approach, the tax benefit is realized in the year it reduces taxable income. Current year stock-based compensation deductions are assumed to be used before any net operating loss carryforwards.

See Note 14, Income Taxes, for more information regarding accounting for income taxes.

(r) Guarantees—Integrys Energy Group follows the guidance of the of the FASB ASC, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. See Note 16, Guarantees, for more information.

(s) Employee Benefits—The costs of pension and other postretirement benefits are expensed over the periods during which employees render service. Our transition obligation related to other postretirement benefit plans was recognized over a 20-year period that began in 1993, and ended in 2012. In computing the expected return on plan assets, we use a market-related value of plan assets. Changes in realized and unrealized investment gains and losses are recognized over the subsequent five years for plans sponsored by WPS, while differences between actual investment returns and the expected return on plan assets are recognized over a five-year period for plans sponsored by IBS and PELLC. The benefit costs associated with employee benefit plans are allocated among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the regulated utilities' net periodic benefit cost calculated under GAAP.

We recognize the funded status of defined benefit postretirement plans on the balance sheet, and recognize changes in the plans' funded status in the year in which the changes occur. Our nonregulated segments record changes in the funded status in accumulated other comprehensive income. The regulated utilities record changes in the funded status to regulatory asset or liability accounts, pursuant to the Regulated Operations Topic of the FASB ASC.

See Note 17, Employee Benefit Plans, for more information.

(t) Stock-Based Compensation—In May 2010, our shareholders approved the 2010 Omnibus Incentive Compensation Plan (2010 Omnibus Plan). Under the provisions of the 2010 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 remaining or forfeited under prior plans. No more than 900,000 shares of stock, plus shares remaining or forfeited under prior plans, can be granted as full value shares in the form of performance shares, restricted stock, or restricted stock units. 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 December 31, 2013, stock options, performance stock rights, and restricted share units were outstanding under the various plans.

Stock Options

Our stock options have a term not longer than 10 years. The exercise price of each stock option is equal to the fair market value of our stock on the date the stock option is granted. Generally, 25% of the stock options granted vest and become exercisable each year on the anniversary of the grant date. For accounting purposes, stock options granted to retirement-eligible employees vest over a shorter period; however, there is no acceleration of when the options become exercisable. Under the provisions of the 2010 Omnibus Plan, no single employee who is our chief executive officer or 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 during any calendar year.

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

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based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. Our expected stock price volatility is estimated using the 10-year historical volatility of our stock price.

Performance Stock Rights

Performance stock rights generally vest over a three-year performance period. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the distribution of these awards is not accelerated. No single employee who is our chief executive officer or one of our other three highest compensated officers (including officers of our subsidiaries) can receive a payout in excess of 250,000 performance shares during any calendar year. Performance stock rights are paid out in shares of our common stock, or eligible employees can elect to defer the value of their awards into the deferred compensation plan and choose among various investment options, some of which are ultimately paid out in our common stock and some of which are ultimately paid out in cash. Eligible employees can only elect to defer up to 80% of the value of their awards. The number of shares paid out is calculated by multiplying a performance percentage by the number of outstanding stock rights at the completion of the performance period. The performance percentage is based on the total shareholder return of our common stock relative to the total shareholder return of a peer group of companies. The payout may range from 0% to 200% of target.

Performance stock rights are accounted for as either an equity award or a liability award, depending on their settlement features. Awards that can only be settled in our common stock are accounted for as equity awards. Awards that an employee has elected to defer, or is still able to defer, into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

Six months prior to the end of the performance period, employees can no longer change their election to defer the value of their performance stock rights into the deferred compensation plan. As a result, any awards not elected for deferral at this point in the performance period will be settled in our common stock. This changes the classification of these awards from a liability award to an equity award. The change in classification is accounted for as an award modification. The fair value on the modification date is used to measure these awards for the remaining six months of the performance period. No incremental compensation expense is recorded as a result of this award modification.

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. Our expected stock price volatility is estimated using one to three years of historical data.

Restricted Shares and Restricted Share Units

Restricted shares and restricted share units generally have a four-year vesting period, with 25% of each award vesting on each anniversary of the grant date. For accounting purposes, awards granted to retirement-eligible employees vest over a shorter period; however, the release of shares to these employees is not accelerated. During 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at December 31, 2013. Restricted share unit recipients do not have voting rights, but they receive forfeitable dividend equivalents in the form of additional restricted share units.

Restricted share units are accounted for as either an equity award or a liability award, depending on their settlement features. Awards that can only be settled in our common stock and cannot be deferred into the deferred compensation plan are accounted for as equity awards. Eligible employees can only elect to defer up to 80% of their awards into the deferred compensation plan. Equity awards are measured based on the fair value on the grant date. Awards that an employee has elected to defer into the deferred compensation plan are accounted for as liability awards and are recorded at fair value each reporting period.

Nonemployee Directors Deferred Stock Units

Each nonemployee director is granted deferred stock units (DSUs), typically in January of each year. 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. Prior to January 1, 2013, under the terms of the agreement, these awards vested immediately, and therefore were expensed on the grant date. Beginning in 2013, these awards generally vest over one year. Therefore, the expense for these awards is recognized pro-rata over the year in which the grant occurs.

(u) 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.

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

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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.

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 group 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.

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

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy. Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, and outstanding commercial paper, the carrying amount for each of these items approximates fair value.

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

See Note 23, Fair Value, for more information.

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(w) Advertising Costs—We expense all advertising costs as incurred, except for those capitalized as direct-response advertising. Costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment. Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years.

(x) New Accounting Pronouncements—

Recently Issued Accounting Guidance Not Yet Effective

Accounting Standards Update (ASU) 2013-04, "Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date," was issued in February 2013. The guidance requires an entity to measure obligations under these arrangements, for which the total amount of the obligation is fixed at the reporting date, as the sum of the reporting entity's portion and any additional amount it expects to pay on behalf of its co-obligors. The guidance also requires additional disclosures about the nature and amount of the obligations. The guidance is effective for us for the reporting period ending March 31, 2014. Adoption of this guidance is not expected to have a significant impact on our financial statements.

ASU 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists," was issued in July 2013. The guidance states that an unrecognized tax benefit should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. However, there are certain exceptions under which the unrecognized tax benefit would be presented in the balance sheet as a liability. The guidance is effective for us for the reporting period ending March 31, 2014. Adoption of this guidance is not expected to have a significant impact on our financial statements.

ASU 2014-01, "Accounting for Investments in Qualified Affordable Housing Projects," was issued in January 2014. The guidance allows investors to use the proportional amortization method to account for investments in qualified affordable housing projects if certain conditions are met. Under that method, which replaces the effective yield method, an investor amortizes the cost of its investment, in proportion to the tax credits and other tax benefits it receives, to income tax expense. The guidance also requires new disclosures for all investments in these types of projects. The guidance is effective for us for the reporting period ending March 31, 2015. Adoption of this guidance is not expected to have a significant impact on our financial statements.

Note 2—Risk Management Activities

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

		December 31, 2013	
(Millions)	Balance Sheet Presentation	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
Financial transmission rights (FTRs)	Current	2.1	0.3
Petroleum product contracts	Current	0.1	—

Coal contracts	Current	—	1.9
Coal contracts	Long-term	0.2	0.8
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	57.6	42.9
Natural gas contracts	Long-term	29.5	18.6
Electric contracts	Current	172.0	117.7
Electric contracts	Long-term	43.9	43.3
	Current	240.1	163.8
	Long-term	75.4	62.8
Total		$315.5	$226.6

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(Millions)	Balance Sheet Presentation	December 31, 2012 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Nonhedge derivatives			
Natural gas contracts	Current	$2.5	$14.0
Natural gas contracts	Long-term	0.9	0.8
FTRs	Current	2.1	0.1
Petroleum product contracts	Current	0.2	—
Coal contracts	Current	0.3	4.7
Coal contracts	Long-term	2.2	4.3
Cash flow hedges			
Natural gas contracts	Current	—	0.4
Nonregulated Segments			
Nonhedge derivatives			
Natural gas contracts	Current	51.7	48.5
Natural gas contracts	Long-term	11.5	7.6
Electric contracts	Current	88.6	114.2
Electric contracts	Long-term	30.7	45.7
	Current	145.4	181.9
	Long-term	45.3	58.4
Total		$190.7	$240.3

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

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

(Millions)	December 31, 2012 Gross Amount	Potential Effects of Netting, Including Cash Collateral	Net Amount
Derivative assets subject to master netting or similar arrangements			
Utility segments	$5.7	$3.0	$2.7
Nonregulated segments	182.5	145.4	37.1
Total	188.2	148.4	39.8
Derivative assets not subject to master netting or similar arrangements	2.5		2.5
Total risk management assets	$190.7		$42.3
Derivative liabilities subject to master netting or similar arrangements			
Utility segments	$15.3	$3.8	$11.5
Nonregulated segments	215.4	159.8	55.6
Total	230.7	163.6	67.1
Derivative liabilities not subject to master netting or similar arrangements	9.6		9.6
Total risk management liabilities	$240.3		$76.7

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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 table. These amounts may offset (or conditionally offset) the net amounts presented in the above table.

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)	December 31, 2013	December 31, 2012
Cash collateral provided to others:		
Related to contracts under master netting or similar arrangements	$37.6	$ 39.9
Other	1.1	1.1
Cash collateral received from others related to contracts under master netting or similar arrangements	0.7	0.2

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)	December 31, 2013	December 31, 2012
Utility segments	$0.6	$ 14.0
Nonregulated segments	76.7	108.9

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)	December 31, 2013	December 31, 2012
Collateral that would have been required:		
Utility segments	$—	$ 10.1
Nonregulated segments	197.6	173.8
Collateral already satisfied:		
Nonregulated segments — Letters of credit	4.5	3.2
Collateral remaining:		
Utility segments	—	10.1
Nonregulated segments	193.1	170.6

Utility Segments

Non-Hedge Derivatives

Utility derivatives include natural gas purchase contracts, coal purchase contracts, financial derivative contracts (futures, options, and swaps), and FTRs used to manage electric transmission congestion costs. The electric and natural gas utility segments use futures, options, and swaps to manage the risks associated with the market price volatility of natural gas supply costs, and the costs of gasoline and diesel fuel used by utility vehicles. The electric utility segment also uses oil futures and options to manage price risk related to coal transportation.

The utilities had the following notional volumes of outstanding derivative contracts:

	December 31, 2013			December 31, 2012		
(Millions, except barrels)	Purchases	Sales	Other Transactions	Purchases	Sales	Other Transactions
Natural gas (therms)	3,124.8	29.3	N/A	1,072.6	0.1	N/A
FTRs (kilowatt-hours)	N/A	N/A	3,633.1	N/A	N/A	4,057.2
Petroleum products (barrels)	102,811.0	14,000.0	N/A	62,811.0	—	N/A
Coal (tons)	4.8	—	N/A	5.1	—	N/A

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

(Millions)	Financial Statement Presentation	2013	2012	2011
Natural gas	Balance Sheet — Regulatory assets (current)	$13.4	$24.6	$(11.3)
Natural gas	Balance Sheet — Regulatory assets (long-term)	2.3	8.3	(7.6)
Natural gas	Balance Sheet — Regulatory liabilities (current)	4.6	(7.8)	8.4
Natural gas	Balance Sheet — Regulatory liabilities (long-term)	0.3	0.3	—
Natural gas	Income Statement — Utility cost of fuel, natural gas, and purchased power	—	0.2	—
Natural gas	Income Statement — Operating and maintenance expense	0.1	—	—
FTRs	Balance Sheet — Regulatory assets (current)	0.1	0.1	(0.4)
FTRs	Balance Sheet — Regulatory liabilities (current)	(0.4)	0.1	(1.3)
Petroleum	Balance Sheet — Regulatory assets (current)	—	0.1	(0.1)
Petroleum	Balance Sheet — Regulatory liabilities (current)	0.1	—	—
Petroleum	Income Statement — Operating and maintenance expense	0.1	—	(0.1)
Coal	Balance Sheet — Regulatory assets (current)	(0.9)	(2.2)	(1.3)
Coal	Balance Sheet — Regulatory assets (long-term)	3.5	0.1	(4.4)
Coal	Balance Sheet — Regulatory liabilities (current)	(0.2)	0.3	—
Coal	Balance Sheet — Regulatory liabilities (long-term)	(2.0)	2.2	(3.7)

Nonregulated Segments

Nonhedge Derivatives

Integrys Energy Services enters into derivative contracts such as futures, forwards, options, and swaps that are used to manage commodity price risk primarily associated with retail electric and natural gas customer contracts.

Integrys Energy Services had the following notional volumes of outstanding derivative contracts:

	December 31, 2013		December 31, 2012	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity				
Natural gas (therms)	1,199.9	1,065.4	782.0	679.0
Electric (kilowatt-hours)	49,186.3	30,813.8	54,127.6	31,809.6
Foreign exchange (Canadian dollars)	—	—	0.4	0.4

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

(Millions)	Income Statement Presentation	2013	2012	2011
Natural gas	Nonregulated revenue	$36.7	$6.8	$14.0
Natural gas	Nonregulated cost of sales	(27.6)	—	—
Natural gas	Nonregulated revenue (reclassified from accumulated OCI) *	(0.3)	(2.0)	(2.3)
Electric	Nonregulated revenue	73.6	(2.0)	(79.0)
Electric	Nonregulated cost of sales	10.8	—	—
Electric	Nonregulated revenue (reclassified from accumulated OCI) *	(3.4)	(4.3)	(1.7)
Total		$89.8	$(1.5)	$(69.0)

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

In the next 12 months, insignificant gains related to discontinued cash flow hedges of electric contracts are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative customer contracts.

Cash Flow Hedges

Prior to July 1, 2011, Integrys Energy Services designated derivative contracts such as futures, forwards, and swaps as accounting hedges under GAAP. These contracts were used to manage commodity price risk associated with customer contracts.

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The tables below show the amounts related to cash flow hedges recorded in OCI and in earnings:

(Millions)	Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion) 2011
Natural gas contracts	$(2.3)
Electric contracts	3.8
Total	$1.5

	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
(Millions)	Income Statement Presentation	2013	2012	2011
Settled/Realized				
Natural gas contracts	Nonregulated revenue	$—	$—	$(9.3)
Electric contracts	Nonregulated revenue	—	—	4.2
Interest rate swaps *	Interest expense	(1.1)	(1.1)	(1.1)
Hedge Designation Discontinued				
Natural gas contracts	Nonregulated revenue	—	—	(0.3)
Interest rate swaps	Interest expense	—	—	(0.2)
Total		$(1.1)	$(1.1)	$(6.7)

* In May 2010, we entered into interest rate swaps that were designated as cash flow hedges to hedge the variability in forecasted interest payments on a debt issuance. These swaps were terminated when the related debt was issued in November 2010. Amounts remaining in accumulated OCI are being reclassified to interest expense over the life of the related debt.

	Gain (Loss) Recognized in Income on Derivative Instruments (Ineffective Portion and Amount Excluded from Effectiveness Testing)	
(Millions)	Income Statement Presentation	2011
Natural gas contracts	Nonregulated revenue	$0.3
Electric contracts	Nonregulated revenue	(0.3)
Total		$—

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, and will be around $11 million. This acquisition is expected to close later in 2014 and will not be material to us.

Acquisition of Compass Energy Services

In May 2013, Integrys Energy Services acquired all of the equity interests of Compass Energy Services, Inc. and its wholly-owned subsidiary (Compass), a nonregulated retail natural gas business supplying commercial and industrial customers primarily in the Mid Atlantic and Ohio regions. This transaction expanded Integrys Energy Services' retail natural gas presence and provides a solid foundation for future growth in these regions.

This acquisition was not material to us. Integrys Energy Services paid $12.4 million to acquire this business. In addition, under the terms of the purchase agreement, the former owners of Compass are eligible to receive additional cash consideration of up to $8.0 million (but no less than $3.0 million), based upon the financial performance of Compass over the five-year period beginning in May 2013 and ending in April 2018. Integrys Energy Services recorded a liability of $7.8 million related to this contingent consideration.

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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	
Inventories	$0.7
Assets from risk management activities (current)	15.1
Other current assets	1.1
Assets from risk management activities (long-term)	9.3
Other long-term assets	6.1
Total assets acquired	$32.3
Liabilities assumed	
Liabilities from risk management activities (current)	$8.3
Other current liabilities	0.5
Liabilities from risk management activities (long-term)	3.4
Total liabilities assumed	$12.2

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.

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 will be amortized over a nine-year period, beginning January 1, 2014.

The purchase was originally financed with a combination of short-term debt and cash provided by operations. WPS replaced the short-term debt with a portion of the proceeds from its 4.752% Senior Notes issued in November 2013. See Note 12, Long-Term Debt, for more information.

WPS received regulatory approval to defer incremental costs associated with the purchase of the facility. Operating costs for the Fox Energy Center subsequent to the date of acquisition are included in our income statement. Due to regulatory deferral, these costs did not impact net income. 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.

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Acquisition of Compressed Natural Gas Fueling Business

On September 1, 2011, we acquired two compressed natural gas fueling businesses through our newly formed, indirect wholly owned subsidiary, ITF. The total consideration paid for the acquisition of Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) was $49.6 million. The total cash payment for this transaction was $42.6 million, which was net of cash acquired of approximately $7 million. In 2012, we received $1.3 million as a result of post-closing working capital adjustments.

Trillium and Pinnacle designed, built, maintained, owned and/or operated compressed natural gas fueling stations in multiple states. In addition, Pinnacle manufactured and sold a patented method to pressurize compressed natural gas.

See Note 9, Goodwill and Other Intangible Assets, for more information related to this acquisition.

Note 4—Discontinued Operations

Discontinued Operations at Holding Company and Other Segment

During 2013, 2012, and 2011, we recorded a $5.9 million after-tax gain, a $1.8 million after-tax gain, and a $0.5 million after-tax loss, respectively, in discontinued operations at the holding company and other segment. We remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations.

Discontinued Operations at Integrys Energy Services Segment

Potential Sale of Combined Locks Energy Center

Integrys Energy Services is currently pursuing the sale of the Combined Locks Energy Center (Combined Locks), a natural gas-fired co-generation facility located in Wisconsin, as part of its long-term energy asset strategy. An agreement to sell Combined Locks is expected to be entered into during the first half of 2014.

The carrying values of the major classes of assets related to Combined Locks classified as held for sale on the balance sheets were as follows at December 31:

(Millions)	2013	2012
Inventories	$0.5	$0.5
Property, plant, and equipment, net of accumulated depreciation of $ – and $0.5, respectively	0.2	2.0
Total assets	$0.7	$2.5

The following table shows the components of discontinued operations related to Combined Locks recorded on the income statements:

(Millions)	2013	2012	2011
Nonregulated revenues	$(0.1)	$0.3	$7.9
Nonregulated cost of sales	(0.2)	(0.5)	(2.0)
Operating and maintenance expense	(2.1)	(0.5)	(0.7)
Depreciation and amortization expense	—	(0.2)	(0.3)
Taxes other than income taxes	—	(0.1)	(0.2)
Income (loss) before taxes	(2.4)	(1.0)	4.7
(Provision) benefit for income taxes	1.1	0.4	(1.8)
Discontinued operations, net of tax	$(1.3)	$(0.6)	$2.9

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

In March 2013, WPS Empire State, Inc., a subsidiary of Integrys Energy Services, 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. The cash proceeds from the sale were $1.6 million. The sale agreement also included a potential annual payment to Integrys Energy Services for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). Integrys Energy Services recorded a pre-tax impairment loss of $1.1 million ($0.7 million after tax) related to Beaver Falls and Syracuse during 2012 when the assets and liabilities were classified as held for sale. This impairment loss is reflected in operating and maintenance expense in the table below.

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The carrying values of the major classes of assets and liabilities related to Beaver Falls and Syracuse classified as held for sale on the balance sheet were as follows:

(Millions)	As of the Closing Date in March 2013	As of December 31, 2012
Inventories	$1.8	$1.8
Other current assets	0.2	—
Property, plant, and equipment	5.7	5.7
Other long-term assets	0.1	0.1
Total assets	$7.8	$7.6
Total liabilities – other current liabilities	$0.4	$0.2

In conjunction with the sale, the buyer assumed certain derivative contracts from WPS Empire State, Inc. Integrys Energy Services maintained these contracts to satisfy certain capacity obligations for its retail electric business and sales to external counterparties. The carrying value of the derivative contract liabilities assumed by the buyer was $6.8 million at closing.

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

(Millions)	2013	2012	2011
Nonregulated revenues	$1.2	$0.6	$5.0
Nonregulated cost of sales	(0.9)	(2.0)	(2.3)
Operating and maintenance expense	0.4*	(3.5)	(3.3)
Depreciation and amortization expense	—	(0.6)	(0.7)
Taxes other than income taxes	(0.3)	(1.4)	(0.9)
Miscellaneous income	—	0.3	—
Income (loss) before taxes	0.4	(6.6)	(2.2)
(Provision) benefit for income taxes	(0.2)	2.6	0.9
Discontinued operations, net of tax	$0.2	$(4.0)	$(1.3)

*Includes a $1.0 million gain on sale at closing

The sale of Beaver Falls and Syracuse may generate immaterial cash flows from a four-year annual earn-out payment. In addition, Integrys Energy Services will continue to settle certain forward financial natural gas swaps under contracts that existed at the time of sale. These settlements will generate cash flows, of which the majority will expire within two years of the sale, and are not considered significant to the overall operations of Beaver Falls and Syracuse. Integrys Energy Services also maintained derivative contracts with Beaver Falls and Syracuse to satisfy certain capacity obligations for its retail electric business and sales to external counterparties. However, a significant portion of these obligations have been novated to the buyer. Integrys Energy Services does not have the ability to significantly influence the operating or financial policies of Beaver Falls and Syracuse and also does not have significant continuing involvement in the operations of Beaver Falls and Syracuse. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Beaver Falls and Syracuse.

Sale of WPS Westwood Generation, LLC

In November 2012, Sunbury Holdings, LLC, a subsidiary of Integrys Energy Services, sold all of the membership interests of WPS Westwood Generation, LLC (Westwood), a waste coal generation plant located in Pennsylvania. The cash proceeds related to the sale were $2.6 million. Integrys Energy Services also received a $4.0 million note receivable from the buyer with a seven and one-half year term. Integrys Energy Services recorded a pre-tax impairment loss of $8.4 million ($5.0 million after tax) related to Westwood during the third quarter of 2012 when the assets and liabilities were classified as held for sale. This impairment loss is reflected in operating and maintenance expense in the table below.

The carrying values of the major classes of assets and liabilities related to Westwood classified as held for sale on the balance sheet were as follows:

(Millions)	As of the Closing Date in November 2012
Inventories	$1.0
Current assets from risk management activities	0.1
Property, plant, and equipment	5.5
Other long-term assets	1.1
Total assets	$7.7
Total liabilities – long-term liabilities from risk management activities	$0.1

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The following table shows the components of discontinued operations related to Westwood recorded on the income statements:

(Millions)	2012	2011
Nonregulated revenues	$9.2	$12.4
Nonregulated cost of sales	(4.4)	(5.6)
Operating and maintenance expense	(14.3) *	(5.7)
Depreciation and amortization expense	(1.0)	(1.4)
Taxes other than income taxes	(0.2)	(0.2)
Miscellaneous income	—	0.1
Interest expense	(0.7)	(0.6)
Loss before taxes	(11.4)	(1.0)
Benefit for income taxes	4.5	0.3
Discontinued operations, net of tax	$(6.9)	$(0.7)

*Includes a $0.6 million loss on sale at closing

Integrys Energy Services will receive interest income for seven and one-half years from the sale date related to the note receivable from the buyer. Integrys Energy Services does not have the ability to significantly influence the operating or financial policies of Westwood and also does not have significant continuing involvement in the operations of Westwood. Therefore, the continuing cash flows discussed above are not considered direct cash flows of Westwood.

Sale of Energy Management Consulting Business

During 2011, Integrys Energy Services recorded a $0.1 million after-tax gain in discontinued operations when contingent payments were earned related to the 2009 sale of its energy management consulting business.

Note 5—Property, Plant, and Equipment

Property, plant, and equipment consisted of the following utility, nonutility, and nonregulated assets at December 31:

(Millions)	2013	2012
Electric utility	$3,558.9	$3,095.8
Natural gas utility	5,428.5	5,050.8
Total utility plant	8,987.4	8,146.6
Less: Accumulated depreciation	3,160.9	3,006.1
Net	5,826.5	5,140.5
Construction work in progress	353.3	203.1
Plant to be retired, net *	14.4	—
Net utility plant	6,194.2	5,343.6
Nonutility plant	142.3	120.2
Less: Accumulated depreciation	81.6	72.3
Net	60.7	47.9
Construction work in progress	38.0	19.6
Net nonutility plant	98.7	67.5
Integrys Energy Services energy assets	109.8	92.0
Integrys Energy Services other	19.7	17.9
Other nonregulated	26.2	14.0

Total nonregulated property, plant, and equipment	155.7	123.9
Less: Accumulated depreciation	46.4	36.3
Net	109.3	87.6
Construction work in progress	8.3	3.2
Net nonregulated property, plant, and equipment	117.6	90.8
Total property, plant, and equipment	$6,410.5	$5,501.9

* In connection with the WPS Consent Decree with the EPA, early retirement of the Weston 1, Pulliam 5, and Pulliam 6 generating units was probable at December 31, 2013. These units are currently included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. The amount presented above is net of accumulated depreciation. See Note 15, Commitments and Contingencies, for more information regarding the Consent Decree.

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We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist. During 2011, Integrys Energy Services recorded a pre-tax noncash impairment loss of $4.6 million related to its Winnebago Energy Center, a landfill-gas-to-electric facility. The impairment charge resulted from lower estimated future cash flows and was primarily driven by forward energy and capacity prices. The impairment charge was reported as part of operating and maintenance expense in the income statement. The fair value of the facility was determined primarily using the income approach, which was based on discounted cash flows that were derived from internal forecasts. These forecasts considered externally supplied forward energy and capacity pricing curves as well as renewable energy credits. Other assumptions included forecasted operating expenses, forecasted capital additions, anticipated working capital requirements, and the discount rate. The 7.5% discount rate used represented the estimated cost of capital for the facility and was also based upon the cash flow period used for the fair value assessment.

See Note 4, Discontinued Operations for additional impairment losses recorded in discontinued operations at Integrys Energy Services during 2012. The impairments were recorded on property and equipment either sold during 2012 or presented on the balance sheet as assets held for sale.

Note 6—Jointly Owned Utility Facilities

WPS holds a joint ownership interest in certain electric generating facilities. WPS is entitled to its share of generating capability and output of each facility equal to its respective ownership interest. WPS also pays its ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit its maximum exposure to additional costs. WPS records its proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets. The amounts were as follows at December 31, 2013:

(Millions, except for percentages and megawatts)	Weston 4		Columbia Energy Center Units 1 and 2		Edgewater Unit 4	
Ownership	70.0	%	31.8	%	31.8	%
WPS's share of rated capacity (megawatts)	374.5		335.2		105.0	
In-service date	2008		1975 and 1978		1969	
Utility plant	$576.8		$172.8		$41.8	
Accumulated depreciation	$(114.6	)	$(111.6	)	$(28.3	)
Construction work in progress	$2.2		$194.8		$0.3	

WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. WPS has supplied its own financing for all jointly owned projects.

Note 7—Regulatory Assets and Liabilities

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

(Millions)	2013	2012	See Note
Regulatory assets (1) (2)			
Environmental remediation costs (net of insurance recoveries) (3)	$653.0	$689.7	15
Unrecognized pension and other postretirement benefit costs (4)	428.8	810.0	17
Merger and acquisition related pension and other postretirement benefit costs (5)	98.3	110.1	
Asset retirement obligations	89.5	73.9	13
Income tax related items	55.3	47.6	14
Termination of a tolling agreement with Fox Energy Company LLC	50.0	—	3

Crane Creek production tax credits (6)	33.6	34.9	
De Pere Energy Center (7)	23.8	26.2	
Unamortized loss on reacquired debt (8)	18.5	18.2	1(n)
Energy efficiency programs (9)	18.0	16.7	
Energy costs receivable through rate adjustments (10)	16.0	18.1	
Derivatives	11.8	30.7	1(h)
Pension and other postretirement costs receivable through rate adjustments (11)	9.4	—	26
Decoupling	9.3	10.6	26
Other	26.7	37.9	
Total regulatory assets	$1,542.0	$1,924.6	
Balance Sheet Presentation			
Current assets	$129.4	$110.8	
Long-term assets	1,412.6	1,813.8	
Total regulatory assets	$1,542.0	$1,924.6	

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

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(2) The following regulatory assets are not earning a return: environmental remediation costs at WPS and UPPCO; unrecognized pension and other postretirement benefit costs at PGL and NSG; merger and acquisition related pension and other postretirement benefit costs at PGL and NSG; unamortized loss on reacquired debt at NSG, PGL, UPPCO and WPS; WPS energy efficiency programs; energy costs receivable through rate adjustments at MERC and WPS; asset retirement obligations and derivatives at all utilities; and decoupling at MGU and UPPCO. However, these regulatory assets are expected to be recovered from customers in future rates.

(3) As of December 31, 2013, we had not yet made cash expenditures for $600.8 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(4) Represents the unrecognized future pension and other postretirement costs resulting from actuarial gains and losses on Integrys Energy Group's defined benefit and other postretirement plans. We are authorized recovery of this regulatory asset over the average future remaining service life of each plan.

(5) Composed of unrecognized benefit costs that existed prior to the PELLC merger and the MERC and MGU acquisitions. MERC and MGU are authorized recovery of this regulatory asset through 2026. PGL and NSG are authorized recovery of the pension portion of this regulatory asset through 2023, and through 2019 for the portion related to other postretirement benefit costs.

(6) In 2012, WPS elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, WPS reversed previously recorded production tax credits. WPS also reduced the depreciable basis of the qualifying facility by the amount of the grant proceeds, which will result in a reduction of depreciation and amortization expense over a 12-year period. WPS recorded a regulatory asset for the deferral of previously recorded production tax credits and is authorized recovery of this net regulatory asset through 2039.

(7) Prior to WPS purchasing the De Pere Energy Center in 2002, WPS had a long-term power purchase contract with the De Pere Energy Center that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. WPS is authorized recovery of this regulatory asset through 2023.

(8) Amounts are recovered over the term of the replacement debt as authorized by the various commissions.

(9) Represents amounts recoverable from customers related to programs at the utility subsidiaries designed to meet energy efficiency standards.

(10) Represents the under-collection of energy costs that will be recovered from customers in the future.

(11) Represents the under-collection of pension and other postretirement costs that will be recovered from customers in the future.

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

(Millions)	2013	2012	See Note
Regulatory liabilities			
Removal costs [1]	$335.3	$318.4	
Decoupling	51.7	15.9	26
Unrecognized pension and other postretirement benefit costs	30.2	17.7	17
Energy costs refundable through rate adjustments [2]	27.2	44.4	

Energy efficiency programs (3)	19.6	8.8	
Uncollectible expense	10.1	10.0	26
Crane Creek depreciation deferral (4)	9.0	9.4	
Derivatives	6.6	4.3	1(h)
Fox Energy Center (5)	5.6	—	3
Other	7.1	7.2	
Total regulatory liabilities	$502.4	$436.1	
Balance Sheet Presentation			
Current liabilities	$101.5	$65.6	
Long-term liabilities	400.9	370.5	
Total regulatory liabilities	$502.4	$436.1	

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

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

(3) Represents amounts refundable to customers related to programs at the utility subsidiaries designed to meet energy efficiency standards.

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

(5) Represents the deferral of incremental costs associated with WPS owning and operating the Fox Energy Center, which was purchased in March 2013. The deferral does not include an allowance for earnings on shareholders' investment of $26.7 million, in accordance with GAAP requirements, which has created the net regulatory liability.

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Note 8—Equity Method Investments

Investments in corporate joint ventures and other companies accounted for under the equity method at December 31, 2013, and 2012 were as follows:

(Millions)	2013	2012
ATC	$508.4	$476.6
INDU Solar Holdings, LLC	24.7	27.5
WRPC	7.0	7.3
Other	0.8	0.8
Equity method investments	$540.9	$512.2

ATC

Our electric transmission investment segment consists of WPS Investments LLC's ownership interest in ATC, which was approximately 34% at December 31, 2013. ATC is a for-profit, transmission-only company regulated by FERC.

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

(Millions)	2013	2012	2011
Balance at the beginning of period	$476.6	$439.4	$416.3
Add: Earnings from equity method investment	89.1	85.3	79.1
Add: Capital contributions	13.7	20.4	8.5
Less: Dividends received	71.0	68.5	64.5
Balance at the end of period	$508.4	$476.6	$439.4

The regulated electric utilities provide construction and other services to ATC and receive network transmission services from ATC. The related party transactions recorded by the regulated electric utilities during the years ended December 31 were as follows:

(Millions)	2013	2012	2011
Total charges to ATC for services and construction	$11.3	$12.5	$13.5
Total costs for network transmission service provided by ATC	104.9	100.3	102.7

INDU Solar Holdings, LLC

Integrys Solar, LLC, a subsidiary of Integrys Energy Services, owns 50% of INDU Solar Holdings, LLC. INDU Solar Holdings, LLC owns solar energy projects in California, Pennsylvania, New Jersey, Arizona, and Massachusetts that deliver electricity and related products to commercial, government, and utility customers under long-term power purchase agreements.

The following table shows changes to our investment in INDU Solar Holdings, LLC during the years ended December 31:

(Millions)	2013	2012	2011
Balance at the beginning of period	$27.5	$28.4	$0.1
Add: Earnings (loss) from equity method investment	1.3	1.1	(0.7)
Add: Capital contributions	—	7.0	29.0
Less: Return of capital to partners	4.1	9.0	—
Balance at the end of period	$24.7	$27.5	$28.4

WRPC

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

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

(Millions)	2013	2012	2011
Balance at the beginning of period	$7.3	$7.7	$8.1
Add: Earnings from equity method investment	1.0	0.8	0.9
Less: Dividends received	1.3	1.2	1.3
Balance at the end of period	$7.0	$7.3	$7.7

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WPS provides services to WRPC, purchases energy from WRPC, and receives net proceeds from sales of energy into the MISO market from WRPC. The related party transactions recorded by WPS during the years ended December 31 were as follows:

(Millions)	2013	2012	2011
Charges to WRPC for operations	$0.9	$0.8	$0.7
Purchases of energy from WRPC	3.7	5.0	4.9
Net proceeds from WRPC sales of energy to MISO	—	2.9	4.7

Financial Data

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

(Millions)	2013	2012	2011
Income statement data			
Revenues	$642.0	$618.3	$575.5
Operating expenses	306.2	292.1	269.6
Other expense	83.7	85.1	81.5
Net income	$252.1	$241.1	$224.4
Earnings from equity method investments	$91.4	$87.2	$79.4

(Millions)	December 31, 2013	December 31, 2012
Balance sheet data		
Current assets	$90.2	$81.1
Noncurrent assets	3,587.2	3,347.4
Total assets	$3,677.4	$3,428.5
Current liabilities	$383.6	$253.0
Long-term debt	1,559.1	1,559.5
Other noncurrent liabilities	134.4	103.5
Shareholders’ equity	1,600.3	1,512.5
Total liabilities and shareholders’ equity	$3,677.4	$3,428.5

Note 9—Goodwill and Other Intangible Assets

The following table shows changes to our gross amount of goodwill and accumulated impairment losses by segment for the years ended December 31, 2013, and 2012:

	Natural Gas Utility		Integrys Energy Services		Holding Company and Other		Total	
(Millions)	2013	2012	2013	2012	2013	2012	2013	2012
Balance as of January 1								
Gross goodwill	$933.5	$933.5	$6.6	$6.6	$15.8	$15.9	$955.9	$956.0
Accumulated impairment losses	(297.6)	(297.6)	—	—	—	—	(297.6)	(297.6)
Net goodwill	635.9	635.9	6.6	6.6	15.8	15.9	658.3	658.4
Adjustment to Trillium and Pinnacle purchase price	—	—	—	—	—	(0.1)	—	(0.1)
	—	—	—	—	3.8	—	3.8	—

Adjustment to ITF patents/intellectual property *								
Balance as of December 31								
Gross goodwill	933.5	933.5	6.6	6.6	19.6	15.8	959.7	955.9
Accumulated impairment losses	(297.6)	(297.6)	—	—	—	—	(297.6)	(297.6)
Net goodwill	$635.9	$635.9	$6.6	$6.6	$19.6	$15.8	$662.1	$658.3

* An immaterial adjustment was made to the gross goodwill balance at ITF in the second quarter of 2013 due to a correction to the life of certain intangible assets.

In the second quarter of 2013, annual impairment tests were completed at all of our reporting units that carried a goodwill balance. No impairments resulted from these tests.

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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. An insignificant amount was recorded as assets held for sale on the balance sheets.

(Millions)	December 31, 2013 Gross Carrying Amount	December 31, 2013 Accumulated Amortization	December 31, 2013 Net Carrying Amount	December 31, 2012 Gross Carrying Amount	December 31, 2012 Accumulated Amortization	December 31, 2012 Net Carrying Amount
Amortized intangible assets						
Customer-related [1]	$26.8	$ (15.7)	$11.1	$22.4	$ (14.7)	$7.7
Contractual service agreements [2]	15.6	(1.8)	13.8	—	—	—
Renewable energy credits [3]	8.4	—	8.4	3.1	—	3.1
Compressed natural gas fueling contract assets [4]	5.6	(2.7)	2.9	5.6	(1.3)	4.3
Customer-owned equipment modifications [5]	4.0	(0.9)	3.1	4.0	(0.5)	3.5
Natural gas and electric contract assets [6]	3.9	(0.5)	3.4	—	—	—
Nonregulated easements [7]	3.7	(1.1)	2.6	3.8	(0.9)	2.9
Patents/intellectual property [8]	3.4	(0.5)	2.9	7.2	(0.3)	6.9
Other	0.5	(0.3)	0.2	0.5	(0.2)	0.3
Total	$71.9	$ (23.5)	$48.4	$46.6	$ (17.9)	$28.7
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	$82.1	$ (23.5)	$58.6	$56.8	$ (17.9)	$38.9

(1) Represents customer relationship assets associated with PELLC's former nonregulated retail natural gas and electric operations, ITF's compressed natural gas fueling operations, and Compass Energy Services. See Note 3, Acquisitions, for more information regarding Integrys Energy Services' acquisition of Compass Energy Services. The remaining weighted-average amortization period for customer-related intangible assets at December 31, 2013, was approximately 11 years.

(2) Represents contractual service agreements related to maintenance on the combustion turbine generators at the Fox Energy Center. The remaining amortization period for these intangible assets at December 31, 2013, was approximately six years.

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

(4) Represents the fair value of ITF contracts acquired in September 2011. The remaining amortization period at December 31, 2013, was approximately seven years.

(5) Relates to modifications made by Integrys Energy Services and ITF to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at December 31, 2013, of approximately ten years.

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

(7) Relates to easements supporting a pipeline at Integrys Energy Services. The easements are amortized on a straight-line basis, with a remaining amortization period at December 31, 2013, of approximately ten years.

(8) Represents the fair value of patents/intellectual property at ITF related to a system for more efficiently compressing natural gas to allow for faster fueling. An immaterial adjustment was made to the intangible assets balance in the second quarter of 2013 as a result of a correction to the life of the intangible assets. The remaining amortization period at December 31, 2013, was approximately nine years.

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

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income for the years ended December 31, 2013, 2012, and 2011, was $2.1 million, $2.5 million, and $1.3 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the years ended December 31, 2013, 2012, and 2011, was $4.2 million, $2.5 million, and $3.4 million, respectively.

An insignificant amount of amortization expense was recorded in discontinued operations for the years ended December 31, 2013, 2012, and 2011.

Amortization expense for the next five fiscal years is estimated to be:

	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—Leases

We lease various property, plant, and equipment. Terms of the operating leases vary, but generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value or (b) exercise a renewal option, as set forth in the lease agreement. Rental expense attributable to operating leases was $12.8 million, $12.4 million, and $12.6 million in 2013, 2012, and 2011, respectively. Future minimum rental obligations under noncancelable operating leases are payable as follows:

Year ending December 31 (Millions)	Payments
2014	$6.7
2015	6.4
2016	6.4
2017	7.4
2018	7.3
Later years	59.4
Total	$93.6

Note 11—Short-Term Debt and Lines of Credit

Information about our short-term borrowings was as follows:

(Millions, except percentages)	2013	2012	2011
Commercial paper			
Amount outstanding at December 31 [1]	$326.0	$482.4	$303.3
Average interest rate on amount outstanding at December 31	0.22%	0.40%	0.31%
Average amount outstanding during the year [2]	$378.4	$326.3	$134.9
Short-term notes payable [3]			
Average amount outstanding during the year [2]	$130.4 [4]	$—	$3.6

(1) Maturity dates ranged from January 2, 2014, through January 27, 2014.

(2) Based on daily outstanding balances during the year.

(3) We did not have short-term notes payable outstanding at December 31, 2013, 2012, and 2011.

(4) Average amount outstanding of a $200.0 million loan used for the purchase of Fox Energy Company LLC. This loan was repaid in November 2013. See Note 3, Acquisitions, for more information regarding this purchase.

We manage our liquidity by maintaining adequate external financing commitments. The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities as of December 31:

(Millions)	Maturity	2013	2012
Revolving credit facility (Integrys Energy Group)	05/17/2014	$275.0	$275.0
Revolving credit facility (Integrys Energy Group)	05/17/2016	200.0	200.0
Revolving credit facility (Integrys Energy Group)	06/13/2017	635.0	635.0
Revolving credit facility (WPS)	05/17/2014	135.0	135.0
Revolving credit facility (WPS)	06/13/2017	115.0	115.0
Revolving credit facility (PGL)	06/13/2017	250.0	250.0

Total short-term credit capacity	$1,610.0	$1,610.0
Less:		
Letters of credit issued inside credit facilities	$52.4	$25.5
Commercial paper outstanding	326.0	482.4
Available capacity under existing agreements	$1,231.6	$1,102.1

Our revolving credit agreements and those of certain of our subsidiaries contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%, excluding non-recourse debt. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

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Note 12—Long-Term Debt

(Millions)				December 31 2013	2012
WPS First Mortgage Bonds [1]					
	Series	Year Due			
	7.125 %	2023		$0.1	$0.1
WPS Senior Notes [1] [2]					
	Series	Year Due			
	4.80 %	2013		—	125.0
	3.95 %	2013		—	22.0
	6.375 %	2015		125.0	125.0
	5.65 %	2017		125.0	125.0
	6.08 %	2028		50.0	50.0
	5.55 %	2036		125.0	125.0
	3.671 %	2042		300.0	300.0
	4.752 %	2044		450.0	—
PGL First and Refunding Mortgage Bonds [3]					
	Series	Year Due			
	KK, 5.00%	2033		—	50.0
	NN-2, 4.625%	2013		—	75.0
	QQ, 4.875%	2038	Mandatory interest reset date on November 1, 2018	75.0	75.0
	RR, 4.30%	2035	Mandatory interest reset date on June 1, 2016	50.0	50.0
	SS, 7.00%	2013		—	45.0
	TT, 8.00%	2018		5.0	5.0
	UU, 4.63%	2019		75.0	75.0
	VV, 2.125%	2030	Mandatory interest reset date on July 1, 2014	50.0	50.0
	WW, 2.625%	2033	Mandatory interest reset date on August 1, 2015	50.0	50.0
	XX, 2.21%	2016		50.0	50.0
	YY, 3.98%	2042		100.0	100.0
	ZZ, 4.00%	2033		50.0	—
	AAA, 3.96%	2043		220.0	—

NSG First Mortgage Bonds [4]					
	Series	Year Due			
	N-2, 4.625%	2013		—	40.0
	O, 7.00%	2013		—	6.5
	P, 3.43%	2027		28.0	28.0
	Q, 3.96%	2043		54.0	—
Integrys Energy Group Unsecured Senior Notes [5]					
	Series	Year Due			
	7.27%	2014		100.0	100.0
	8.00%	2016		55.0	55.0
	4.17%	2020		250.0	250.0
Integrys Energy Group Unsecured Junior Subordinated Notes [6]					
	Series	Year Due			
	6.11%	2066	Interest to become variable on December 1, 2016	269.8	269.8
	6.00%	2073	Mandatory interest reset date on August 1, 2023	400.0	—
Total				3,056.9	2,246.4
Unamortized discount on debt				(0.7)	(1.2)
Total debt				3,056.2	2,245.2
Less current portion				100.0	313.5
Total long-term debt				$2,956.2	$1,931.7

(1) WPS's First Mortgage Bonds and Senior Notes are subject to the terms and conditions of WPS's First Mortgage Indenture. Under the terms of the Indenture, substantially all property owned by WPS is pledged as collateral for these outstanding debt securities. All of these debt securities require semi-annual payments of interest. WPS Senior Notes become noncollateralized if WPS retires all of its outstanding First Mortgage Bonds and no new mortgage indenture is put in place.

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(2) In December 2013, WPS's $125.0 million of 4.80% Senior Notes matured, and the outstanding principal balance was repaid.

In November 2013, WPS issued $450.0 million of 4.752% Senior Notes. These notes are due in November 2044.

In February 2013, WPS's $22.0 million of 3.95% Senior Notes matured, and the outstanding principal balance was repaid.

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

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

In November 2013, PGL's $45.0 million 7.00% Series SS First and Refunding Mortgage Bonds matured, and the outstanding principal balance was repaid.

In August 2013, PGL issued $220.0 million of 3.96% Series AAA First and Refunding Mortgage Bonds. These bonds are due in August 2043.

In May 2013, PGL's $75.0 million 4.625% Series NN-2 First and Refunding Mortgage Bonds matured, and the outstanding principal balance was repaid.

In April 2013, PGL bought back its $50.0 million of 5.00% Series KK First and Refunding Mortgage Bonds that were due in February 2033. In the same month, PGL issued $50.0 million of 4.00% Series ZZ First and Refunding Mortgage Bonds. These bonds are due in February 2033.

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

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

In November 2013, NSG's $6.5 million 7.00% Series O First Mortgage Bonds matured, and the outstanding principal balance was repaid.

In May 2013, NSG's $40.0 million 4.625% Series N-2 First Mortgage Bonds matured, and the outstanding principal balance was repaid. In the same month, NSG issued $54.0 million of 3.96% Series Q First Mortgage Bonds. These Bonds are due in May 2043.

(5) In June 2014, our 7.27% Unsecured Senior Notes will mature. As a result, the $100.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at December 31, 2013.

(6) In August 2013, we issued $400.0 million of Junior Subordinated Notes. These notes are considered hybrid instruments with a combination of debt and equity characteristics. Interest is payable quarterly at the stated rate of

6.00% for the first ten years, after which time it changes to a floating rate. These notes are due in August 2073.

The 6.11% Junior Subordinated Notes are considered hybrid instruments with a combination of debt and equity characteristics. Under a replacement capital covenant with the holders of our 4.17% Unsecured Senior Notes due November 1, 2020, prior to December 1, 2036 any amounts redeemed or repurchased in excess of 10% of the principal amount outstanding must first be replaced with a specified amount of proceeds from the sale of qualifying securities that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the 6.11% Junior Subordinated Notes.

Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. In addition, certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

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

(Millions)	Payments
2014	$100.0
2015	125.0
2016	105.0
2017	125.0
2018	5.0
Later years	2,596.9
Total	$3,056.9

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Note 13—Asset Retirement Obligations

The utility segments have asset retirement obligations primarily related to removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation facilities, office buildings, and service centers; dismantling wind generation projects; disposal of PCB-contaminated transformers; closure of fly-ash landfills at certain generation facilities; and removal of above ground storage tanks. The utilities establish regulatory assets and liabilities to record the differences between ongoing expense recognition under the asset retirement obligation accounting rules, and the ratemaking practices for retirement costs authorized by the applicable regulators. Integrys Energy Services has asset retirement obligations related to the removal of solar equipment components.

The following table shows changes to our asset retirement obligations through December 31, 2013:

(Millions)	Utilities	Integrys Energy Services	Total
Asset retirement obligations at December 31, 2010	$320.9	$—	$320.9
Accretion	17.1	—	17.1
Additions and revisions to estimated cash flows	64.4 *	0.5	64.9
Settlements	(5.7)	—	(5.7)
Asset retirement obligations at December 31, 2011	396.7	0.5	397.2
Accretion	20.3	0.1	20.4
Additions and revisions to estimated cash flows	(2.4)	1.6	(0.8)
Settlements	(5.6)	—	(5.6)
Asset retirement obligations at December 31, 2012	409.0	2.2	411.2
Accretion	20.8	0.1	20.9
Additions and revisions to estimated cash flows	70.1 *	0.5	70.6
Settlements	(11.2)	—	(11.2)
Asset retirement obligations at December 31, 2013	$488.7	$2.8	$491.5

* Revisions were made to estimated cash flows related to asset retirement obligations primarily due to an increase in the weighted average cost to retire a foot of natural gas distribution pipe at PGL.

Note 14—Income Taxes

Deferred Income Tax Assets and Liabilities

The principal components of deferred income tax assets and liabilities recognized on the balance sheets as of December 31 are included in the table below. Certain temporary differences are netted in the table when the offsetting amount is recorded as a regulatory asset or liability. This is consistent with regulatory treatment.

(Millions)	2013	2012
Deferred income tax assets		
Tax credit carryforwards	$113.5	$105.1
Price risk management	13.0	59.6
Other	98.5	76.5
Total deferred income tax assets	$225.0	$241.2
Valuation allowance	(8.2)	(7.2)
Net deferred income tax assets	$216.8	$234.0
Deferred income tax liabilities		
Plant-related	$1,373.8	$1,215.7

Employee benefits	79.6	49.1
Regulatory deferrals	78.8	60.8
Other	43.5	47.9
Total deferred income tax liabilities	$1,575.7	$1,373.5
Total net deferred income tax liabilities	$1,358.9	$1,139.5
Balance sheet presentation		
Current deferred income tax assets	$31.4	$64.3
Long-term deferred income tax liabilities	1,390.3	1,203.8
Net deferred income tax liabilities	$1,358.9	$1,139.5

Deferred tax credit carryforwards at December 31, 2013, included $73.9 million of alternative minimum tax credits, which can be carried forward indefinitely. Other deferred tax credit carryforwards included $20.9 million of general business credits, which have a carryback period of one year and a carryforward period of 20 years. The majority of the general business credit carryforwards will expire in 2032. Deferred tax credit carryforwards also included $15.2 million of foreign tax credits, which have a carryback period of one year and a carryforward period of 10 years. The majority of the foreign tax credit carryforwards will expire in 2020. We also had $3.5 million of deferred state tax credit carryforwards, which have a carryforward period of five years. The majority of the state tax credit carryforwards will expire in 2018.

At December 31, 2013, we had deferred income tax assets of $45.4 million reflecting federal operating loss carryforwards, which have a carryback period of two years and a carryforward period of 20 years. We also had deferred income tax assets of $16.4 million reflecting state operating loss carryforwards. The majority of the state operating loss carryforwards relate to Wisconsin and have a carryforward period of 20 years. Any deferred tax assets that are not used to offset future taxable income will expire between 2020 and 2032 as follows:

2020 through 2025	$6.3 million
2026 through 2031	$9.2 million
2032	$46.3 million

Valuation allowances are established for certain state operating losses and foreign tax credits based on our projected ability to realize these benefits by offsetting future taxable income. Realization is dependent on generating sufficient taxable income prior to expiration. As of December 31, 2013, the entire valuation allowance was related to noncurrent deferred income tax assets. There was no significant change in the valuation allowance during 2013.

Regulated utilities record certain adjustments related to deferred income taxes to regulatory assets and liabilities. As the related temporary differences reverse, the regulated utilities prospectively refund taxes to or collect taxes from customers for which deferred taxes were recorded in prior years at rates potentially different than current rates or upon enactment of changes in tax law. The net regulatory asset for these net recoveries and other regulatory tax effects totaled $51.6 million and $42.1 million at December 31, 2013, and 2012, respectively. See Note 7, Regulatory Assets and Liabilities, for more information.

Income Before Taxes

Income before taxes includes the following components of foreign and domestic income:

	For the Years Ended December 31		
(Millions)	2013	2012	2011
Domestic	$560.8	$443.9	$363.4
Foreign	—	(0.1)	(0.1)
Total income before taxes	$560.8	$443.8	$363.3

Provision for Income Taxes

The components of the provision for income taxes were as follows:

(Millions)	2013	2012	2011
Current provision			
Federal	$7.8	$3.5	$(44.2)
State	5.9	0.4	6.0
Foreign	0.1	(0.1)	(0.2)
Total current provision	13.8	3.8	(38.4)
Deferred provision			
Federal	174.8	128.3	158.7
State	14.9	20.1	14.6

Foreign	—	—	0.1
Total deferred provision	189.7	148.4	173.4
Investment tax credits, net	8.4	5.2	(1.1)
Penalties	(0.1)	(0.3)	0.7
Unrecognized tax benefits	0.4	(3.0)	0.9
Interest	(1.4)	(4.3)	(2.2)
Total provision for income taxes related to continuing operations	210.8	149.8	133.3
Total provision for income taxes related to discontinued operations	(6.9)	(9.3)	1.1
Total	$203.9	$140.5	$134.4

Statutory Rate Reconciliation

The following table presents a reconciliation of the difference between the effective tax rate and the amount computed by applying the statutory federal tax rate to income before taxes.

(Millions, except for percentages)	2013 Rate	2013 Amount	2012 Rate	2012 Amount	2011 Rate	2011 Amount
Statutory federal income tax	35.0 %	$196.3	35.0 %	$155.4	35.0 %	$127.2
State income taxes, net	3.9	21.8	4.8	21.1	5.3	19.1
Federal tax credits	(0.1)	(0.5)	(1.7)	(7.6)	(2.0)	(7.1)
Benefits and compensation	(0.7)	(4.2)	(2.1)	(9.4)	(2.3)	(8.4)
Other differences, net	(0.5)	(2.6)	(2.2)	(9.7)	0.7	2.5
Effective income tax	37.6 %	$210.8	33.8 %	$149.8	36.7 %	$133.3

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(Millions)	2013	2012	2011
Balance at January 1	$11.3	$22.4	$30.4
Increase related to tax positions taken in prior years	2.2	0.9	3.1
Decrease related to tax positions taken in prior years	(8.7)	(6.7)	(1.6)
Increase related to tax positions taken in current year	0.3	0.6	0.9
Decrease related to settlements	(1.5)	(5.7)	(9.4)
Decrease related to lapse of statutes	—	(0.2)	(1.0)
Balance at December 31	$3.6	$11.3	$22.4

We had accrued interest of $0.8 million and accrued penalties of $0.4 million related to unrecognized tax benefits at December 31, 2013. We had accrued interest of $2.5 million and accrued penalties of $2.0 million related to unrecognized tax benefits at December 31, 2012.

Our effective tax rate could be affected by recognition of $1.9 million of unrecognized tax benefits related to continuing operations in periods after December 31, 2013. Also, our provision for income taxes could be affected by recognition of $0.5 million of unrecognized tax benefits related to discontinued operations in periods after December 31, 2013.

Our subsidiaries file income tax returns in the United States federal jurisdiction, in various state and local jurisdictions, and in Canada.

With a few exceptions, we are no longer subject to federal income tax examinations by the IRS for years prior to 2011. During 2013, the IRS completed its examinations of 2009 and 2010.

We file state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. With a few exceptions, we are no longer subject to state and local tax examinations for years prior to 2008. As of December 31, 2013, we were subject to examination by state or local tax authorities for the 2008 through 2012 tax years in our major state operating jurisdictions as follows:

State	Year
Illinois	2008
Michigan	2008
Minnesota	2011

Wisconsin	2009

During 2013, the Minnesota taxing authority initiated and completed its examination of the 2005 through 2010 tax years, and the Michigan taxing authority initiated its examination of the 2008 through 2011 tax years. During 2013, the Illinois taxing authority completed its examination of the 2007 tax year, which resulted in an adjustment to the provision for income taxes, of which a large portion was reported as discontinued operations. This settlement, combined with other certain state income tax examinations and a remeasurement of uncertain tax positions, decreased our liability for unrecognized tax benefits by $6.5 million. We reduced the provision for income taxes related to these items, of which a large portion was reported as discontinued operations.

As of December 31, 2013, we were subject to examination by foreign income tax authorities for the 2008 through 2012 tax years. With a few exceptions, we are no longer subject to foreign income tax examinations by tax authorities for years prior to 2008.

In the next 12 months, it is also reasonably possible that we and our subsidiaries will settle open examinations in multiple taxing jurisdictions related to tax years prior to 2011, resulting in a further decrease in unrecognized tax benefits of as much as $0.9 million.

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Note 15—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 Integrys Energy Services 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 December 31, 2013, including those of our subsidiaries.

			Payments Due By Period					
(Millions)	Date Contracts Extend Through	Total Amounts Committed	2014	2015	2016	2017	2018	Later Years
Natural gas utility supply and transportation	2028	$845.9	$181.2	$169.6	$158.4	$122.0	$71.7	$143.0
Electric utility								
Purchased power *	2029	772.3	80.6	32.8	28.8	27.6	27.0	575.5
Coal supply and transportation	2018	99.5	46.3	31.0	12.0	6.7	3.5	—
Nonregulated electricity and natural gas supply	2020	697.9	492.8	145.2	49.9	8.1	1.5	0.4
Total		$2,415.6	$800.9	$378.6	$249.1	$164.4	$103.7	$718.9

* Includes minimum future commitments for UPPCO related to power purchase contracts of $9.9 million for the years 2014 to 2023. In January 2014, we announced an agreement to sell UPPCO. See Note 29, Subsequent Event, for more information.

We and our subsidiaries also had commitments of $909.0 million in the form of purchase orders issued to various vendors at December 31, 2013, that relate to normal business operations, including construction projects. Included in this amount are purchase orders issued to various vendors of UPPCO for $12.2 million.

(b) Environmental Matters

Air Permitting Violation Claims

Weston and Pulliam Clean Air Act (CAA) Issues:
In November 2009, the EPA issued a Notice of Violation (NOV) to WPS alleging violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. WPS reached a settlement agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the U.S. District Court (Court) in March 2013, after a public comment period. The final Consent Decree includes:

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

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain Weston and Pulliam units. As of December 31, 2013, the early retirement of certain Weston and Pulliam units mentioned in the Consent Decree was considered probable. See Note 5, Property, Plant, and Equipment, for more information.

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

In May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of December 31, 2013. 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

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agreement with the EPA regarding this NOV and signed a Consent Decree. This Consent Decree was approved by the Court in June 2013, after a public comment period. The final Consent Decree includes:

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

As mentioned above, the Consent Decree contains a requirement to refuel, repower, and/or retire certain of the Columbia and Edgewater units. As of December 31, 2013, no decision had been made on how to address this requirement. Therefore, retirement of the Columbia and Edgewater units mentioned in the Consent Decree was not considered probable.

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

Weston Title V Air Permit:
In November 2010, the WDNR provided a draft revised permit for the Weston 4 plant. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR and met with the WDNR to resolve these issues. In September 2011, the WDNR issued an updated draft revised permit and a request for public comments. Due to the significance of the changes to the draft revised permit, the WDNR re-issued the draft revised permit for additional comments in February 2013. In July 2012, Clean Wisconsin filed a lawsuit against the WDNR alleging failure to issue or delay in issuing the Weston Title V permit. WPS and the WDNR both filed motions to dismiss Clean Wisconsin's lawsuit, which the Court granted in February 2013. Clean Wisconsin appealed this decision but voluntarily filed a dismissal of its appeal in July 2013, closing the lawsuit. The dismissal resulted from the WDNR sending the proposed permit to the EPA for action. Later in July 2013, the WDNR issued the 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 Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also filed Petitions for Review and requests for contested case proceedings regarding various aspects of the permit. In October 2013, the WDNR granted all parties' requests for contested case proceedings, except one issue where they asked for clarifying information from WPS. The Petitions for Review, by all parties, have been stayed pending the resolution of the contested cases.

Mercury and Interstate Air Quality Rules

Mercury:
The State of Wisconsin's mercury rule requires a 40% reduction from historical baseline mercury emissions, beginning January 1, 2010, through the end of 2014. Beginning in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the historical baseline. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts, but less than 150 megawatts, must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of December 31, 2013, WPS estimated capital costs of approximately $8 million for its wholly owned plants to achieve the required reductions. The capital costs are expected to be recovered in future rates.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics Standards (MATS), which will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. The State of Wisconsin is in the process of revising the state mercury rule to be consistent with the MATS rule. We are currently evaluating options for achieving the emission limits specified in this rule, but we do not anticipate the cost of compliance to be significant. We expect to recover future compliance costs 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. In October 2012, the EPA and several other parties filed petitions for a rehearing of the D.C. Circuit's decision, which the D.C. Circuit denied in January 2013. In March 2013, the EPA requested that the United States Supreme Court (Supreme Court) review the D.C. Circuit's rejection of CSAPR. In June 2013, the Supreme Court agreed to review the case.

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.

Due to the uncertainty surrounding this rulemaking, we are currently unable to predict whether WPS will have to purchase additional emission allowances, idle or abandon certain units, or change how certain units are operated. WPS expects to recover any future compliance costs in future rates. The potential impact on Integrys Energy Services is not expected to be material.

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Manufactured Gas Plant Remediation

Our natural gas utilities, their predecessors, and certain former affiliates operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, our natural gas utilities are required to undertake remedial action with respect to some of these materials. They are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a "multi-site" 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 $599.7 million that we have estimated and accrued for as of December 31, 2013, 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 December 31, 2013, cash expenditures for environmental remediation not yet recovered in rates were $49.3 million. Our balance sheets also include a regulatory asset of $649.0 million at December 31, 2013, which is net of insurance recoveries received of $65.2 million, related to the expected recovery through rates of both cash expenditures and estimated future expenditures.

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

Note 16—Guarantees

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at December 31, 2013	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$597.4	$375.1	$2.2	$220.1
Standby letters of credit (2)	55.8	45.1	10.6	0.1
Surety bonds (3)	21.9	21.9	—	—
Other guarantees (4)	56.3	1.2	1.5	53.6
Total guarantees	$731.4	$443.3	$14.3	$273.8

(1) Consists of (a) $430.3 million, $5.0 million, and $2.0 million to support the business operations of Integrys Energy Services, IBS, and UPPCO, respectively, and (b) $111.5 million and $48.6 million related to natural gas supply at MERC and MGU, respectively. These guarantees are not reflected on our balance sheets.

(2)

At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $53.8 million issued to support Integrys Energy Services' operations and $2.0 million issued to support ITF, MERC, MGU, NSG, PGL, UPPCO, and WPS. These amounts are not reflected on our balance sheets.

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

(4) Consists of (a) $35.0 million to support Integrys Energy Services' 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 Integrys Energy Services' 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 tax law; (c) $3.0 million related to the sale of WPS Beaver Falls Generation, LLC and WPS Syracuse Generation, LLC. Integrys Energy Services' guaranteed the buyer's performance under certain derivative contracts that the buyer assumed from WPS Empire State, Inc. in conjunction with the sale. See Note 4, Discontinued Operations, for more information; (d) $2.4 million related to the performance of an operating and maintenance agreement by ITF; and (e) $5.9 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.

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Note 17—Employee Benefit Plans

Defined Benefit Plans

We and our subsidiaries maintain a noncontributory, qualified pension plan covering the majority of our employees, as well as several unfunded nonqualified retirement plans. In addition, we and our subsidiaries offer multiple other postretirement benefit plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. Our defined benefit pension plans were closed to all new hires as of February 16, 2012. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013.

We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Benefits		Other Benefits	
(Millions)	2013	2012	2013	2012
Change in benefit obligation				
Obligation at January 1	$1,784.9	$1,563.1	$621.0	$576.8
Service cost	30.2	46.0	24.9	20.8
Interest cost	71.2	78.0	24.8	28.5
Plan amendments	—	—	0.2	—
Actuarial (gain) loss, net	(153.1)	196.6	(73.4)	14.3
Participant contributions	—	—	10.6	10.6
Benefit payments	(91.5)	(98.8)	(34.0)	(32.1)
Federal subsidy on benefits paid	—	—	2.2	2.1
Obligation at December 31	$1,641.7	$1,784.9	$576.3	$621.0
Change in fair value of plan assets				
Fair value of plan assets at January 1	$1,348.1	$1,099.5	$424.4	$285.5
Actual return on plan assets	205.4	173.6	57.8	46.3
Employer contributions	65.7	173.8	11.3	114.1
Participant contributions	—	—	10.6	10.6
Benefit payments	(91.5)	(98.8)	(34.0)	(32.1)
Fair value of plan assets at December 31	$1,527.7	$1,348.1	$470.1	$424.4
Funded Status at December 31	$(114.0)	$(436.8)	$(106.2)	$(196.6)

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Benefits		Other Benefits	
(Millions)	2013	2012	2013	2012
Current liabilities	$9.0	$7.9	$0.2	$0.3
Long-term liabilities	105.0	428.9	106.0	196.3
Total liabilities	$114.0	$436.8	$106.2	$196.6

The accumulated benefit obligation for the defined benefit pension plans was $1,489.1 million and $1,594.7 million at December 31, 2013, and 2012, respectively.

Information for the qualified pension plans with an accumulated benefit obligation in excess of plan assets is presented in the following table as of December 31:

(Millions)	2013	2012
Projected benefit obligation	$65.4	$1,784.9
Accumulated benefit obligation	63.0	1,594.7
Fair value of plan assets	—	1,348.1

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

	Pension Benefits		Other Benefits	
(Millions)	2013	2012	2013	2012
Accumulated other comprehensive loss (pre-tax) [1]				
Net actuarial loss	$33.3	$59.1	$0.7	$1.3
Prior service costs (credits)	—	0.2	(0.2)	(0.6)
Total	$33.3	$59.3	$0.5	$0.7
Net regulatory assets [2]				
Net actuarial loss	$399.3	$683.1	$8.9	$117.3
Prior service costs (credits)	2.4	6.2	(12.0)	(14.3)
Total	$401.7	$689.3	$(3.1)	$103.0

(1) Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

(2) Amounts related to the regulated utilities are recorded as regulatory assets or liabilities.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2014:

(Millions)	Pension Benefits	Other Benefits
Net actuarial losses	$34.6	$2.5
Prior service costs (credits)	0.6	(2.4)
Total 2014 – estimated amortization	$35.2	$0.1

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 Benefits		
(Millions)	2013	2012	2011	2013	2012	2011
Service cost	$30.2	$46.0	$41.4	$24.9	$20.8	$19.0
Interest cost	71.2	78.0	80.1	24.8	28.5	29.5
Expected return on plan assets	(105.5)	(107.9)	(100.0)	(30.6)	(28.2)	(21.4)
Amortization of transition obligation	—	—	—	—	0.3	0.3
Amortization of prior service cost (credit)	4.0	5.0	5.3	(2.5)	(3.4)	(3.9)
Amortization of net actuarial loss	56.7	34.0	18.1	8.4	6.6	4.0
Net periodic benefit cost	$56.6	$55.1	$44.9	$25.0	$24.6	$27.5

Assumptions – Pension and Other Postretirement Benefit Plans

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

	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
Discount rate	4.92%	4.07%	4.83%	3.96%
Rate of compensation increase	4.24%	4.25%	N/A	N/A
Assumed medical cost trend rate	N/A	N/A	6.50%	7.00%

Ultimate trend rate	N/A	N/A	5.00%	5.00%
Year ultimate trend rate is reached	N/A	N/A	2019	2019
Assumed dental cost trend rate	N/A	N/A	5.00%	5.00%

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

	Pension Benefits		
	2013	2012	2011
Discount rate	4.07%	5.10%	5.80%
Expected return on assets	8.00%	8.25%	8.25%
Rate of compensation increase	4.25%	4.25%	4.26%

	Other Benefits		
	2013	2012	2011
Discount rate	3.96%	4.94%	5.66%
Expected return on assets	8.00%	8.25%	8.25%
Assumed medical cost trend rate (under age 65)	7.00%	7.00%	7.50%
Ultimate trend rate	5.00%	5.00%	5.00%
Year ultimate trend rate is reached	2019	2016	2016
Assumed medical cost trend rate (over age 65)	7.00%	7.50%	8.00%
Ultimate trend rate	5.00%	5.50%	5.50%
Year ultimate trend rate is reached	2019	2016	2016
Assumed dental cost trend rate	5.00%	5.00%	5.00%

We establish our expected return on assets assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. For 2014, the expected return on assets assumption for the plans is 8.00%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for our health care plans. For the year ended December 31, 2013, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

	One-Percentage-Point	
(Millions)	Increase	Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$8.2	$(6.5)
Effect on the health care component of the accumulated postretirement benefit obligation	80.6	(65.5)

Pension and Other Postretirement Benefit Plan Assets

Our investment policy includes various guidelines and procedures designed to ensure assets are invested in an appropriate manner to meet expected future benefits to be earned by participants. The investment guidelines consider a broad range of economic conditions. Our policy is established and administered in a manner that is compliant at all times with applicable regulations.

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

The Board of Directors established the Employee Benefits Administrator Committee (composed of members of management) to manage the operations and administration of all benefit plans and trusts. The committee monitors the asset allocation, and the portfolio is rebalanced when necessary.

Pension and other postretirement benefit plan investments are recorded at fair value. See Note 1(v), Fair Value, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

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The following table provides the fair values of our investments by asset class:

	December 31, 2013							
	Pension Plan Assets				Other Benefit Plan Assets			
(Millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$2.0	$36.6	$—	$38.6	$—	$4.0	$—	$4.0
Equity securities:								
United States equity	100.4	445.1	—	545.5	21.4	132.2	—	153.6
International equity	114.1	429.0	—	543.1	19.5	125.5	—	145.0
Fixed income securities:								
United States government	—	93.6	—	93.6	121.2	0.7	—	121.9
Foreign government	—	16.9	2.4	19.3	—	—	—	—
Corporate debt	—	250.0	1.3	251.3	—	—	—	—
Asset-backed securities	—	61.8	—	61.8	—	—	—	—
Other	—	17.4	—	17.4	1.0	—	—	1.0
	216.5	1,350.4	3.7	1,570.6	163.1	262.4	—	425.5
401(h) other benefit plan assets invested as pension assets (1)	(6.1)	(37.9)	(0.1)	(44.1)	6.1	37.9	0.1	44.1
Total (2)	$210.4	$1,312.5	$3.6	$1,526.5	$169.2	$300.3	$0.1	$469.6

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

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

	December 31, 2012							
	Pension Plan Assets				Other Benefit Plan Assets			
(Millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$6.4	$25.3	$—	$31.7	$—	$9.5	$—	$9.5
Equity securities:								
United States equity	167.9	403.0	—	570.9	27.8	129.0	—	156.8
International equity	96.0	300.4	—	396.4	15.6	92.9	—	108.5
Fixed income securities:								
United States government	—	100.3	—	100.3	112.7	—	—	112.7
Foreign government	—	20.4	4.1	24.5	—	—	—	—
Corporate debt	—	197.3	1.0	198.3	—	—	—	—
Asset-backed securities	—	56.5	0.1	56.6	—	—	—	—
Other	—	11.3	—	11.3	1.1	—	—	1.1

	270.3	1,114.5	5.2	1,390.0	157.2	231.4	—	388.6
401(h) other benefit plan assets invested as pension assets [1]	(7.1)	(29.3)	(0.1)	(36.5)	7.1	29.3	0.1	36.5
Total [2]	$263.2	$1,085.2	$5.1	$1,353.5	$164.3	$260.7	$0.1	$425.1

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

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

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy:

(Millions)	Foreign Government Debt	Corporate Debt	Asset-Backed Securities	Total
Beginning balance at January 1, 2013	$4.1	$1.0	$0.1	$5.2
Net realized and unrealized losses	(0.3)	(0.4)	—	(0.7)
Purchases	0.6	—	—	0.6
Sales	(2.0)	(0.4)	—	(2.4)
Transfers into Level 3	—	1.4	—	1.4
Transfers out of Level 3	—	(0.3)	(0.1)	(0.4)
Ending balance at December 31, 2013	$2.4	$1.3	$—	$3.7
Net unrealized losses related to assets still held at the end of the period	$(0.2)	$(0.3)	$—	$(0.5)

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(Millions)	Foreign Government Debt	Corporate Debt	Asset-Backed Securities	Total
Beginning balance at January 1, 2012	$5.7	$2.1	$—	$7.8
Net realized and unrealized gains (losses)	0.5	0.2	—	0.7
Purchases	1.2	0.5	—	1.7
Sales	(2.0)	(0.4)	—	(2.4)
Transfers into Level 3	—	—	0.1	0.1
Transfers out of Level 3	(1.3)	(1.4)	—	(2.7)
Ending balance at December 31, 2012	$4.1	$1.0	$0.1	$5.2
Net unrealized losses related to assets still held at the end of the period	$0.3	$0.1	$—	$0.4

Cash Flows Related to Pension and Other Postretirement Benefit Plans

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. We expect to contribute $72.3 million to our pension plans and $11.9 million to our other postretirement benefit plans in 2014, dependent upon various factors affecting us, including our liquidity position and tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and other postretirement benefits. In addition, the table shows the expected federal subsidies, provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003, which will partially offset other postretirement benefits.

(Millions)	Pension Benefits	Other Benefits	Federal Subsidies
2014	$125.1	$30.0	$2.2
2015	123.3	32.5	2.3
2016	126.1	35.0	2.5
2017	129.3	37.5	2.6
2018	125.9	39.9	2.7
2019 through 2023	657.6	234.1	15.8

Defined Contribution Benefit Plans

We maintain 401(k) Savings Plans for substantially all of our full-time employees. A percentage of employee contributions are matched through an employee stock ownership plan (ESOP) contribution or cash contribution up to certain limits. Certain union employees receive a contribution to their ESOP account regardless of their participation in the 401(k) Savings Plan. The ESOP held 3.8 million shares of our common stock (market value of $206.4 million) at December 31, 2013. Certain employees participate in a defined contribution pension plan, in which certain amounts are contributed to an employee's account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $36.4 million in 2013, $19.1 million in 2012, and $17.0 million in 2011.

We maintain deferred compensation plans that enable certain key employees and nonemployee directors to defer payment of a portion of their compensation or fees on a pre-tax basis. Nonemployee directors can defer up to 100% of their director fees. Compensation is generally deferred in the form of cash and is indexed to certain investment options or our common stock. The deemed dividends paid on our common stock are automatically reinvested.

The deferred compensation arrangements for which distributions are made solely in our common stock are classified as an equity instrument on the balance sheets. Changes in the fair value of this portion of the deferred compensation obligation are not recognized. The deferred compensation obligation classified as an equity instrument was $24.8 million at December 31, 2013, and $23.9 million at December 31, 2012.

The portion of the deferred compensation obligation that is indexed to various investment options and allows for distributions in cash is classified as a liability on the balance sheets. The liability is adjusted, with a charge or credit to expense, to reflect changes in the fair value of the deferred compensation obligation. The obligation classified within other long-term liabilities was $53.4 million at December 31, 2013, and $42.9 million at December 31, 2012. The costs incurred under this arrangement were $6.5 million in 2013, $3.1 million in 2012, and $2.1 million in 2011.

The deferred compensation programs are partially funded through shares of our common stock that are held in a rabbi trust. The common stock held in the rabbi trust is classified as a reduction of equity in a manner similar to accounting for treasury stock. The total cost of our common stock held in the rabbi trust was $23.0 million at December 31, 2013, and $17.7 million at December 31, 2012.

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Note 18—Stock-Based Compensation

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

(Millions)	2013	2012	2011
Stock options	$1.8	$2.0	$1.8
Performance stock rights	2.7	5.0	3.5
Restricted shares and restricted share units	10.2	9.7	6.1
Nonemployee director deferred stock units	0.9	1.0	1.0
Total stock-based compensation expense	$15.6	$17.7	$12.4
Deferred income tax benefit	$6.2	$7.1	$5.0

No stock-based compensation cost was capitalized during 2013, 2012, and 2011.

Stock Options

The following table shows the weighted-average fair values per stock option granted along with the assumptions incorporated into the binomial lattice valuation models:

	2013 Grant	2012 Grant	2011 Grant
Weighted-average fair value per stock option	$6.03	$6.30	$6.57
Expected term	5 years	5 years	5 years
Risk-free interest rate	0.18% – 2.11%	0.17% – 2.18%	0.27% – 3.90%
Expected dividend yield	5.33%	5.28%	5.34%
Expected volatility	24%	25%	25%

A summary of stock option activity for 2013, and information related to outstanding and exercisable stock options at December 31, 2013, 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, 2012	2,046,355	$ 49.25		
Granted	319,234	56.00		
Exercised	(797,705)	48.56		
Forfeited	(15,510)	56.00		
Expired	(2,000)	44.73		
Outstanding at December 31, 2013	1,550,374	$ 50.93	6.2	$6.6
Exercisable at December 31, 2013	810,086	$ 49.96	4.6	$4.3

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 December 31, 2013. This is calculated as the difference between our closing stock price on December 31, 2013, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during 2013, 2012, and 2011 was $9.0 million, $11.0 million, and $2.8 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $3.6 million during 2013, $4.4 million during 2012, and not significant during 2011.

As of December 31, 2013, $1.0 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.4 years.

Performance Stock Rights

The table below reflects the assumptions used in the Monte Carlo valuation models to estimate the fair value of the outstanding performance stock rights at December 31:

	2013	2012	2011
Risk-free interest rate	0.13% – 1.27%	0.17% – 1.27%	0.00% – 1.27%
Expected dividend yield	5.28% – 5.34%	5.18% – 5.34%	5.28% – 5.34%
Expected volatility	15% – 36%	14% – 36%	21% – 36%

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A summary of the 2013 activity related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights	Weighted-Average Fair Value *
Outstanding at December 31, 2012	108,314	$ 65.38
Granted	22,636	48.50
Award modifications	28,789	39.80
Distributed	(94,758)	72.36
Adjustment for final payout	21,867	72.36
Forfeited	(1,099)	48.50
Outstanding at December 31, 2013	85,749	$ 46.62

* 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 2013, 2012, and 2011 was $48.50, $52.70, and $49.21 per performance stock right, respectively.

A summary of the 2013 activity related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2012	189,093
Granted	90,496
Award modifications	(28,789)
Distributed	(61,753)
Adjustment for final payout	14,255
Forfeited	(4,398)
Outstanding at December 31, 2013	198,904

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of December 31, 2013, was $29.77 per performance stock right.

As of December 31, 2013, $1.3 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.7 years.

The total intrinsic value of performance stock rights distributed during 2013, 2012, and 2011 was $8.8 million, $4.7 million, and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during 2013, 2012, and 2011 was $3.6 million, $1.9 million, and $2.5 million, respectively.

Restricted Shares and Restricted Share Units

A summary of the 2013 activity related to all restricted share unit awards (equity and liability awards) is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2012	505,690	$ 48.38
Granted	196,894	55.93
Dividend equivalents	24,089	52.20

Vested and released	(208,682)	46.36
Forfeited	(6,690)	52.56
Outstanding at December 31, 2013	511,301	$ 52.24

As of December 31, 2013, $10.2 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.3 years.

The total intrinsic value of restricted share and restricted share unit awards vested and released during 2013, 2012, and 2011 was $11.7 million, $10.7 million, and $7.5 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted shares and restricted share units during 2013, 2012, and 2011 was $4.7 million, $4.3 million, and $3.0 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during 2013, 2012, and 2011 was $55.93, $53.24, and $49.39 per unit, respectively.

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Note 19—Common Equity

We had the following changes to issued common stock:

Balance at December 31, 2010	77,781,685
Shares issued	
Stock-based compensation	204,331
Stock Investment Plan	149,470
Employee Stock Ownership Plan	105,845
Rabbi trust shares	48,788
Restricted stock shares cancelled	(2,213)
Balance at December 31, 2011	78,287,906
Balance at December 31, 2012 *	78,287,906
Shares issued	
Stock-based compensation	972,718
Stock Investment Plan	298,532
Employee Stock Ownership Plan	248,724
Rabbi trust shares	111,296
Balance at December 31, 2013	79,919,176

* We did not issue equity during 2012.

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

Period	Method of meeting requirements
Beginning 02/05/2014 (1)	Purchasing shares on the open market
02/05/2013 – 02/04/2014	Issued new shares (2)
05/01/2011 – 02/04/2013	Purchased shares on the open market
01/01/2011 – 04/30/2011	Issued new shares (2)

(1) The decision was made in conjunction with the announcement of the proposed sale of UPPCO. See Note 29, Subsequent Event, for more information.

(2) These stock issuances increased equity $79.8 million and $22.2 million in 2013 and 2011, respectively.

The following table reconciles common shares issued and outstanding:

	2013 Shares	Average Cost *	2012 Shares	Average Cost *
Common stock issued	79,919,176		78,287,906	
Less:				
Deferred compensation rabbi trust	473,796	$48.50	385,439	$46.03
Total common shares outstanding	79,445,380		77,902,467	

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

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Earnings Per Share

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

(Millions, except per share amounts)	2013	2012	2011
Numerator:			
Net income from continuing operations	$350.0	$294.0	$230.0
Discontinued operations, net of tax	4.8	(9.7)	0.5
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries	0.1	0.2	—
Net income attributed to common shareholders — basic	$351.8	$281.4	$227.4
Effect of dilutive securities			
Deferred compensation	(0.1)	—	—
Net income attributed to common shareholders — diluted	$351.7	$281.4	$227.4
Denominator:			
Average shares of common stock — basic	79.5	78.6	78.6
Effect of dilutive securities			
Stock-based compensation	0.4	0.5	0.5
Deferred compensation	0.2	0.2	—
Average shares of common stock — diluted	80.1	79.3	79.1
Earnings per common share			
Basic	$4.43	$3.58	$2.89
Diluted	4.39	3.55	2.87

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

(Millions)	2013	2012	2011
Stock-based compensation	0.3	0.7	0.7
Deferred compensation	0.1	—	—

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 December 31, 2013, these covenants restricted the payment of any dividends beyond the amount allowed under our subsidiary requirements described above.

As of December 31, 2013, total restricted net assets were $1,848.7 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $143.1 million at December 31, 2013.

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

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

Capital Transactions with Subsidiaries

During 2013, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
ITF [1]	$ —	$ —	$ 44.3
MERC	—	21.0	13.0
MGU	—	12.5	8.0
NSG [2]	12.0	—	—
UPPCO	—	6.5	—
WPS	108.6	35.0	200.0
WPS Investments, LLC [3]	71.0	—	13.6
Total	$ 191.6	$ 75.0	$ 278.9

(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) NSG 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.

(3) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At December 31, 2013, we had an 86.22% ownership interest, while WPS and UPPCO had an 11.36% and 2.42% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2013, all equity contributions to WPS Investments, LLC were made solely by us.

Note 20—Preferred Stock of Subsidiary

Our subsidiary, WPS, has 1,000,000 authorized shares of preferred stock with no mandatory redemption and a $100 par value. Outstanding shares owned by third parties were as follows at December 31:

(Millions, except share amounts)	2013		2012	
Series	Shares Outstanding	Carrying Value	Shares Outstanding	Carrying Value
5.00%	130,692	$13.1	130,692	$13.1
5.04%	29,898	3.0	29,898	3.0
5.08%	49,905	5.0	49,905	5.0
6.76%	150,000	15.0	150,000	15.0
6.88%	150,000	15.0	150,000	15.0
Total	510,495	$51.1	510,495	$51.1

All shares of WPS preferred stock of all series are of equal rank except as to dividend rates and redemption terms. Payment of dividends from any earned surplus or other available surplus is not restricted by the terms of any indenture or other undertaking by WPS. Each series of outstanding preferred stock is redeemable in whole or in part at WPS's option at any time on 30 days' notice at the respective redemption prices. WPS may not redeem less than all, nor purchase any, of our preferred stock during the existence of any dividend default.

In the event of WPS's dissolution or liquidation, the holders of preferred stock are entitled to receive (a) the par value of their preferred stock out of the corporate assets other than profits before any of such assets are paid or distributed to the holders of common stock and (b) the amount of dividends accumulated and unpaid on their preferred stock out of the surplus or net profits before any of such surplus or net profits are paid to the holders of common stock. Thereafter, the remainder of the corporate assets, surplus, and net profits would be paid to the holders of common stock.

The preferred stock has no pre-emptive, subscription, or conversion rights, and has no sinking fund provisions.

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Note 21—Accumulated Other Comprehensive Loss

The following table show the changes, net of tax, to our accumulated other comprehensive loss during the year ended December 31, 2013:

Year Ended December 31, 2013 (Millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Beginning balance at December 31, 2012	$ (5.2)	$ (35.7)	$ (40.9)
Other comprehensive income before reclassifications	0.7	13.2	13.9
Amounts reclassified out of accumulated other comprehensive loss	1.4	2.4	3.8
Net current period other comprehensive income	2.1	15.6	17.7
Ending balance at December 31, 2013	$ (3.1)	$ (20.1)	$ (23.2)

The following table shows the reclassifications out of accumulated other comprehensive loss during the year ended December 31, 2013:

(Millions)	Amount Reclassified	Affected Line Item in the Statements of Income
Losses on cash flow hedges		
Utility commodity derivative contracts	$0.2	Operating and maintenance expense (1)
Nonregulated commodity derivative contracts	3.7	Nonregulated revenues
Interest rate hedges	1.1	Interest expense
	5.0	Total before tax
	3.6	Tax expense
	1.4	Net of tax
Defined benefit plans		
Amortization of prior service costs	4.3	(2)
Amortization of net actuarial gains	(0.2)	(2)
	4.1	Total before tax
	1.7	Tax expense
	2.4	Net of tax
Total reclassifications	$3.8	

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

(2) These items are included in the computation of net periodic benefit cost. See Note 17, Employee Benefit Plans, for more information.

Note 22—Variable Interest Entities

Consolidated Variable Interest Entities

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture is loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At December 31, 2013, and

December 31, 2012, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of AMP Trillium LLC assets and liabilities included on our balance sheets were also not significant.

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. The joint venture was established to own and operate compressed natural gas fueling stations. ITF and Paper Transport Inc. each initially owned 50% of the joint venture. We determined that the joint venture is a variable interest entity and that ITF was the primary beneficiary, which required us to consolidated the assets, liabilities, and statements of income of the joint venture. At December 31, 2012, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. The carrying amounts of Integrys PTI CNG Fuels LLC assets and liabilities included on our December 31, 2012, balance sheet were also not significant. In June 2013, ITF purchased Paper Transport Inc.'s 50% ownership interest of the joint venture, and it became a wholly owned subsidiary.

Unconsolidated Variable Interest Entities

In 2013, ITF formed EVO Trillium LLC as a joint venture with Environmental Alternative Fuels LLC. ITF owns 15% and Environmental Alternative Fuels LLC owns 85% of the joint venture. This joint venture was established to own and operate compressed natural gas fueling stations. We determined that this joint venture is a variable interest entity but that consolidation is not required since we are not its primary beneficiary, as we don't have the power to direct its activities. We instead account for this variable interest entity as an equity method investment. At December 31, 2013, the

assets and liabilities on our balance sheet 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 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 December 31, 2013, and December 31, 2012, 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.

We also had a variable interest in Fox Energy Company LLC through a power purchase agreement at WPS that contained a tolling arrangement related to the cost of fuel. In connection with the purchase of Fox Energy Company LLC in March 2013, WPS paid $50.0 million for the early termination of this 500-megawatt agreement. See Note 3, Acquisitions, for more information regarding this purchase. We evaluated this variable interest entity for possible consolidation and determined that consolidation was not required since we were not the primary beneficiary of the variable interest entity. The assets and liabilities on our December 31, 2012, balance sheet 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.

Note 23—Fair Value

Fair Value Measurements

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:

	December 31, 2013			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$2.4	$7.7	$—	$10.1
Financial transmission rights (FTRs)	—	—	2.1	2.1
Petroleum product contracts	0.1	—	—	0.1
Coal contracts	—	—	0.2	0.2
Nonregulated Segments				
Natural gas contracts	16.3	35.2	35.6	87.1
Electric contracts	65.1	134.9	15.9	215.9
Total Risk Management Assets	$83.9	$177.8	$53.8	$315.5
Investment in exchange-traded funds	$15.9	$—	$—	$15.9
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$0.5	$0.6	$—	$1.1

FTRs	—	—	0.3	0.3
Coal contracts	—	—	2.7	2.7
Nonregulated Segments				
Natural gas contracts	14.3	22.0	25.2	61.5
Electric contracts	98.8	58.7	3.5	161.0
Total Risk Management Liabilities	$113.6	$81.3	$31.7	$226.6
Contingent consideration related to the acquisition of Compass Energy Services (Compass) *	$—	$—	$7.8	$7.8

* See Note 3, Acquisitions, for more information.

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	December 31, 2012			
(Millions)	Level 1	Level 2	Level 3	Total
Assets				
Risk Management Assets				
Utility Segments				
Natural gas contracts	$0.3	$3.1	$—	$3.4
FTRs	—	—	2.1	2.1
Petroleum product contracts	0.2	—	—	0.2
Coal contracts	—	—	2.5	2.5
Nonregulated Segments				
Natural gas contracts	21.4	36.4	5.4	63.2
Electric contracts	48.4	61.3	9.6	119.3
Total Risk Management Assets	$70.3	$100.8	$19.6	$190.7
Investment in exchange-traded funds	$11.8	$—	$—	$11.8
Liabilities				
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$1.1	$14.1	$—	$15.2
FTRs	—	—	0.1	0.1
Coal contracts	—	—	9.0	9.0
Nonregulated Segments				
Natural gas contracts	17.7	36.9	1.5	56.1
Electric contracts	54.9	91.1	13.9	159.9
Total Risk Management Liabilities	$73.7	$142.1	$24.5	$240.3

The risk management assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO market. See Note 2, Risk Management Activities, for more information on derivative instruments.

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

	Nonregulated Segments — Natural Gas Contracts					
	Year Ended December 31, 2013			Year Ended December 31, 2012		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	$—	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	—	$—	N/A	2.0
Transfers into Level 3 from	—	7.1	N/A	—	3.7	N/A

	Nonregulated Segments — Electric Contracts					
	Year Ended December 31, 2013			Year Ended December 31, 2012		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	N/A	$—	(0.3)	N/A	$—	$—
Transfers into Level 2 from	$—	N/A	7.3	$—	N/A	(13.0)
Transfers into Level 3 from	(0.2)	8.7	N/A	—	(7.9)	N/A

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The significant unobservable inputs used in the valuations that resulted in categorization within Level 3 were as follows at December 31, 2013. The amounts and percentages listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a transaction to be classified as Level 3.

	Fair Value (Millions)				
	Assets	Liabilities	Valuation Technique	Unobservable Input	Average or Range
Utility Segments					
FTRs	$ 2.1	$ 0.3	Market-based	Forward market prices ($/megawatt-month) (1)	$174.52
Coal contracts	0.2	2.7	Market-based	Forward market prices ($/ton) (2)	$11.73 — $14.30
Nonregulated Segments					
Natural gas contracts	35.6	25.2	Market-based	Forward market prices ($/dekatherm) (3)	($1.53) — $17.30
				Probability of default(4)	11.6% — 51.0 %
Electric contracts	15.9	3.5	Market-based	Forward market prices ($/megawatt-hours) (3)	($3.30) — $9.25
				Probability of default(4)	26.0 %
				Option volatilities(5)	14.8% — 199.9 %
				Monthly curve shaping(6)	(33.3)%
Contingent consideration related to the acquisition of Compass	N/A	7.8	Income-based	Growth rate(7)	(13.2)% — 49.3 %

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

(2) Represents third-party forward market pricing.

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

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

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

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

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

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

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

2013	Nonregulated Segments			Utility Segments		
(Millions)	Natural Gas	Electric	Contingent Consideration*	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$3.9	$(4.3)	$ —	$2.0	$ (6.5)	$(4.9)
Net realized and unrealized gains (losses) included in earnings	(1.8)	14.0	(0.1)	2.0	—	14.1
Net unrealized gains (losses) recorded as regulatory assets or liabilities	—	—	—	(0.3)	0.4	0.1
Purchases	7.4	6.0	(7.7)	4.9	—	10.6
Sales	—	(1.1)	—	(0.2)	—	(1.3)
Settlements	(6.2)	(3.7)	—	(6.6)	3.6	(12.9)
Net transfers into Level 3	7.1	8.5	—	—	—	15.6
Net transfers out of Level 3	—	(7.0)	—	—	—	(7.0)
Balance at the end of the period	$10.4	$12.4	$ (7.8)	$1.8	$ (2.5)	$14.3
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$(1.8)	$14.0	$ —	$—	$ —	$12.2

* Represents the contingent consideration related to the acquisition of Compass. See Note 3, Acquisitions, for more information.

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2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$ 8.3	$ (11.5)	$ 2.2	$ (6.9)	$ (7.9)
Net realized and unrealized gains (losses) included in earnings	3.8	(14.5) *	1.8	—	(8.9) *
Net unrealized gains recorded as regulatory assets or liabilities	—	—	0.2	5.8	6.0
Purchases	—	7.8	4.9	—	12.7
Sales	—	—	(0.1)	—	(0.1)
Settlements	(9.9)	8.8	(7.0)	(5.4)	(13.5)
Net transfers into Level 3	3.7	(7.9)	—	—	(4.2)
Net transfers out of Level 3	(2.0)	13.0	—	—	11.0
Balance at the end of the period	$ 3.9	$ (4.3)	$ 2.0	$ (6.5)	$ (4.9)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 3.8	$ (14.5) *	$ —	$ —	$ (10.7) *

* Includes a $1.2 million net unrealized loss reported as discontinued operations. See Note 4, Discontinued Operations, for more information.

2011	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contracts	Total
Balance at the beginning of the period	$ 30.2	$ (14.9)	$ 2.9	$ 2.5	$ 20.7
Net realized and unrealized gains (losses) included in earnings	32.3	(20.7) *	(1.7)	—	9.9 *
Net unrealized losses recorded as regulatory assets or liabilities	—	—	(1.7)	(8.0)	(9.7)
Net unrealized gains included in other comprehensive loss	—	0.6	—	—	0.6
Purchases	—	2.2	5.9	—	8.1
Sales	—	—	(0.1)	—	(0.1)
Settlements	(30.4)	7.0	(3.1)	(1.4)	(27.9)
Net transfers into Level 3	0.6	(5.9)	—	—	(5.3)
Net transfers out of Level 3	(24.4)	20.2	—	—	(4.2)
Balance at the end of the period	$ 8.3	$ (11.5)	$ 2.2	$ (6.9)	$ (7.9)
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$ 32.3	$ (20.7) *	$ —	$ —	$ 11.6 *

* Includes a $0.5 million net unrealized gain reported as discontinued operations. See Note 4, Discontinued Operations, for more information.

Realized and unrealized gains and losses included in earnings related to Integrys Energy Services’ risk management assets and liabilities are recorded through nonregulated revenue or nonregulated cost of sales on the statements of income, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through utility cost of fuel, natural gas, and purchased power on the statements of income.

Fair Value of Financial Instruments

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

	December 31, 2013		December 31, 2012	
(Millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	$3,056.2	$3,031.6	$2,245.2	$2,425.8
Preferred stock of subsidiary	51.1	61.2	51.1	52.7

Note 24—Advertising Costs

Capitalized direct-response advertising costs, net of accumulated amortization, totaled $5.2 million and $5.5 million as of December 31, 2013, and December 31, 2012, respectively. We did not record any significant impairments during the years ended December 31, 2013, 2012, and 2011.

The amortization of direct-response advertising costs was $5.7 million, $3.8 million, and $1.5 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Other advertising expense was $8.5 million, $7.1 million, and $7.4 million for the years ended December 31, 2013, 2012, and 2011, respectively.

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Note 25—Miscellaneous Income

Total miscellaneous income was as follows at December 31:

(Millions)	2013	2012	2011
Equity portion of AFUDC	$10.8	$2.9	$0.7
Seams elimination charge adjustment (SECA) settlement at Integrys Energy Services	5.7	—	—
Federal excise tax credit	4.1	—	—
Key executive life insurance income for retired employees	2.2	2.6	2.3
Gains (losses) on exchange-traded funds held at IBS	2.2	1.3	(0.1)
Other	4.8	2.5	2.4
Total miscellaneous income	$29.8	$9.3	$5.3

Note 26—Regulatory Environment

Wisconsin

2014 Rates

In December 2013, the PSCW issued a final written order for WPS, effective January 1, 2014. It authorized a net retail electric rate decrease of $12.8 million and a net retail natural gas rate increase of $4.0 million, reflecting a 10.20% return on common equity. The order also included a common equity ratio of 50.14% in WPS's regulatory capital structure. The retail electric rate impact consists of a rate increase, offset by a portion of estimated fuel cost over-collections from customers in 2013 of the same amount. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. Additionally, the retail electric rate decrease includes the deferral of the difference between the 2012 fuel refund and the 2013 rate increase discussed below. The retail natural gas rate impact consists of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes include the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 related to the Pulliam and Weston sites. See Note 15, Commitments and Contingencies, for more information. Additionally, the order requires WPS to terminate its existing decoupling mechanism, beginning January 1, 2014.

2013 Rates

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

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

2012 Rates

In December 2011, the PSCW issued a final written order for WPS, effective January 1, 2012. The order authorized a retail electric rate increase of $8.1 million and required a retail natural gas rate decrease of $7.2 million. The retail electric rate increase was driven by projected increases in fuel and purchased power costs. However, to the extent that actual fuel and purchased power costs exceeded a 2% variance from costs included in rates, they were deferred for recovery or refund in a future rate proceeding. The rate order allowed for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection and reflected reduced contributions to the Focus on Energy Program. The rate order also allowed for the deferral of direct CSAPR compliance costs, including carrying costs.

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Michigan

2014 MGU Rates

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

MGU Depreciation Case

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

2014 UPPCO Rates

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

2012 UPPCO Rates

In December 2011, the MPSC issued a final written order for UPPCO, effective January 1, 2012. The order authorized a retail electric rate increase of $4.2 million. The rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in UPPCO's regulatory capital structure. The order stated that if UPPCO filed a rate case in 2013, the earliest effective date for new final rates or self-implemented rates would be January 1, 2014. Additionally, the order required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2013. The new decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. It includes an annual 1.5% cap based on distribution revenues approved in the rate case. UPPCO had no decoupling mechanism in place during 2012.

In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. This decision was not appealed. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. However, in August 2012, the MPSC issued an order stating it had the authority to approve UPPCO's decoupling mechanism, as UPPCO's decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement. Therefore, in the third quarter of 2012, UPPCO reversed the $1.5 million previously expensed in the first quarter of 2012.

Illinois

2015 Rate Cases

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

Qualifying Infrastructure Plant (QIP) Rider

In July 2013, Illinois Public Act 98-0057 (formerly Senate Bill 2266), The Natural Gas Consumer, Safety & Reliability Act, became law. The Act gives PGL a cost recovery mechanism for Illinois natural gas infrastructure upgrades that will be collected through a surcharge on customer bills. Later in July 2013, the ICC adopted emergency rules to implement the law, and in December 2013, issued an order to adopt permanent rules replacing the

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emergency rules. This Act eliminated a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation. In September 2013, PGL filed with the ICC requesting the proposed rider, and the ICC approved the tariff in January 2014. The rider became effective on January 1, 2014.

2013 Rates

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

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

2012 Rates

In January 2012, the ICC issued a final written order, effective January 21, 2012. The order authorized a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG. The rates for PGL reflected a 9.45% return on common equity and a common equity ratio of 49.00% in PGL's regulatory capital structure. The rates for NSG reflected a 9.45% return on common equity and a common equity ratio of 50.00% in NSG's regulatory capital structure. The rate order also approved a permanent decoupling mechanism.

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

Minnesota

2014 Rate Case

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

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

2011 Rates

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

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Note 27—Segments of Business

At December 31, 2013, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the regulated electric utility operations of UPPCO and WPS.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company.
- Integrys Energy Services is a diversified nonregulated retail energy supply and services company that primarily sells electricity and natural gas in deregulated markets. In addition, Integrys Energy Services invests in energy assets with renewable attributes, primarily distributed solar assets.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company, ITF, and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS.

All of our operations and assets are located within the United States. The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
2013 (Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$2,093.6	$1,332.0	$ —	$3,425.6	$2,166.2	$42.8	$ —	$5,634.6
Intersegment revenues	11.4	0.1	—	11.5	1.3	1.4	(14.2)	—
Depreciation and amortization expense	136.0	98.6	—	234.6	11.4	21.1	(0.5)	266.6
Earnings from equity method investments	—	—	89.1	89.1	1.3	1.1	—	91.5
Miscellaneous income	1.2	9.8	—	11.0	8.5	23.6	(13.3)	29.8
Interest expense	50.2	36.4	—	86.6	2.0	52.9	(13.3)	128.2
Provision (benefit) for income taxes	78.9	67.3	35.2	181.4	48.0	(18.6)	—	210.8
Net income (loss) from continuing operations	124.0	113.4	53.9	291.3	79.4	(20.7)	—	350.0
Discontinued operations	—	—	—	—	(1.1)	5.9	—	4.8
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.1	—	0.1
Net income (loss) attributed to common shareholders	123.4	110.9	53.9	288.2	78.3	(14.7)	—	351.8
Total assets	5,672.0	3,514.4	508.5	9,694.9	989.2	1,345.9	(786.5)	11,243.5
	370.0	615.0	—	985.0	15.8	60.0	—	1,060.8

Cash expenditures for long-lived assets

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2012 (Millions)	Regulated Operations Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$1,662.1	$1,297.4	$ —	$2,959.5	$1,217.6	$35.3	$ —	$4,212.4
Intersegment revenues	9.9	—	—	9.9	0.9	1.9	(12.7)	—
Depreciation and amortization expense	131.8	89.0	—	220.8	10.3	20.1	(0.5)	250.7
Earnings from equity method investments	—	—	85.3	85.3	1.1	0.8	—	87.2
Miscellaneous income	0.6	2.6	—	3.2	1.1	20.9	(15.9)	9.3
Interest expense	47.3	35.9	—	83.2	2.1	50.8	(15.9)	120.2
Provision (benefit) for income taxes	61.4	49.4	32.9	143.7	25.8	(19.7)	—	149.8
Net income (loss) from continuing operations	94.0	110.4	52.4	256.8	52.6	(15.4)	—	294.0
Discontinued operations	—	—	—	—	(11.5)	1.8	—	(9.7)
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Noncontrolling interest in subsidiaries	—	—	—	—	—	0.2	—	0.2
Net income (loss) attributed to common shareholders	93.4	107.9	52.4	253.7	41.1	(13.4)	—	281.4
Total assets	5,446.2	3,041.3	476.6	8,964.1	749.2	1,267.8	(653.7)	10,327.4
Cash expenditures for long-lived assets	375.1	163.9	—	539.0	30.9	24.4	—	594.3

2011 (Millions)	Regulated Operations Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Income Statement								
External revenues	$1,987.2	$1,307.3	$ —	$3,294.5	$1,372.0	$19.4	$ —	$4,685.9
Intersegment revenues	10.8	—	—	10.8	1.1	1.5	(13.4)	—
Depreciation and amortization expense	126.1	88.5	—	214.6	10.3	23.3	(0.5)	247.7
Earnings (losses) from equity method investments	—	—	79.1	79.1	(0.7)	1.0	—	79.4
Miscellaneous income	2.2	0.8	—	3.0	1.0	18.3	(17.0)	5.3

Interest expense	48.4	41.8	—	90.2	1.7	53.3	(17.0)	128.2
Provision (benefit) for income taxes	61.2	59.2	31.3	151.7	(7.7)	(10.7)	—	133.3
Net income (loss) from continuing operations	103.9	103.0	47.8	254.7	(7.1)	(17.6)	—	230.0
Discontinued operations	—	—	—	—	1.0	(0.5)	—	0.5
Preferred stock dividends of subsidiary	(0.6)	(2.5)	—	(3.1)	—	—	—	(3.1)
Net income (loss) attributed to common shareholders	103.3	100.5	47.8	251.6	(6.1)	(18.1)	—	227.4
Total assets	5,033.0	2,982.9	439.4	8,455.3	891.5	1,215.3	(578.9)	9,983.2
Cash expenditures for long-lived assets	199.3	84.1	—	283.4	16.7	10.0	—	310.1

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Note 28—Quarterly Financial Information (Unaudited)

(Millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2013					
Total revenues	$1,678.2	$1,116.0	$1,129.7	$1,710.7	$5,634.6
Operating income (loss)	293.1	(6.9)	55.3	226.2	567.7
Net income (loss) from continuing operations	182.2	(3.9)	39.4	132.3	350.0
Net income (loss)	188.3	(4.7)	38.8	132.4	354.8
Net income (loss) attributed to common shareholders	187.5	(5.4)	38.1	131.6	351.8
Earnings (loss) per common share (basic) *					
Net income (loss) from continuing operations	$2.30	$(0.06)	$0.49	$1.64	$4.37
Discontinued operations, net of tax	0.08	(0.01)	(0.01)	—	0.06
Earnings (loss) per common share (basic)	2.38	(0.07)	0.48	1.64	4.43
Earnings (loss) per common share (diluted) *					
Net income (loss) from continuing operations	2.29	(0.06)	0.48	1.63	4.33
Discontinued operations, net of tax	0.08	(0.01)	(0.01)	—	0.06
Earnings (loss) per common share (diluted)	2.37	(0.07)	0.47	1.63	4.39
2012					
Total revenues	$1,247.9	$839.6	$927.7	$1,197.2	$4,212.4
Operating income	153.1	87.1	108.5	118.8	467.5
Net income from continuing operations	98.8	51.7	74.3	69.2	294.0
Net income	99.7	49.6	66.3	68.7	284.3
Net income attributed to common shareholders	98.9	48.8	65.7	68.0	281.4
Earnings per common share (basic) *					
Net income from continuing operations	$1.25	$0.65	$0.94	$0.87	$3.70
Discontinued operations, net of tax	0.01	(0.03)	(0.10)	—	(0.12)
Earnings per common share (basic)	1.26	0.62	0.84	0.87	3.58
Earnings per common share (diluted) *					
Net income from continuing operations	1.24	0.65	0.93	0.86	3.67
Discontinued operations, net of tax	0.01	(0.03)	(0.10)	—	(0.12)
Earnings per common share (diluted)	1.25	0.62	0.83	0.86	3.55

* Earnings per share for the individual quarters do not total the year ended earnings per share amount because of changes to the average number of shares outstanding and changes in incremental issuable shares throughout the year. Earnings per share for the individual quarters differ by insignificant amounts from previously reported amounts due to the classification of certain asset groups as discontinued operations. See Note 4, Discontinued Operations, for more information.

Because of various factors, the quarterly results of operations are not necessarily comparable.

Note 29—Subsequent Event

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 had approached us in early 2013 about the potential sale, and we came to an agreement in

January 2014 that was approved by our Board of Directors. The transaction is subject to regulatory approvals and is expected to close later in 2014. Following the sale, we will provide various administrative and operational services to UPPCO during a transition period of 18 to 30 months.

The following table shows the balances of the assets and liabilities of UPPCO that are included in the disposal group:

(Millions)	December 31, 2013
Current assets	$26.5
Property, plant, and equipment, net of accumulated depreciation of $88.9 million	193.8
Other long-term assets	51.5
Total assets	$271.8
Current liabilities	$21.2
Long-term liabilities	$32.4
Total liabilities	$53.6

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I. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON FINANCIAL STATEMENTS

To the Board of Directors and Stockholders of Integrys Energy Group, Inc.:
We have audited the accompanying consolidated balance sheets of Integrys Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Integrys Energy Group, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin
February 27, 2014

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended December 31, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management Report on Internal Control over Financial Reporting

For Integrys Energy Group's Management Report on Internal Control over Financial Reporting, see Section A of Item 8.

Reports of Independent Registered Public Accounting Firm

For Integrys Energy Group's Reports of Independent Registered Public Accounting Firm, see Sections B and I of Item 8.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information required by this Item regarding our directors, Section 16 compliance, and members of the Audit Committee and the Audit Committee financial expert can be found in our Proxy Statement for our Annual Meeting of Shareholders to be held May 15, 2014 (Proxy Statement), under the captions "Election of Directors," "Ownership of Voting Securities – Section 16(a) Beneficial Ownership Reporting Compliance," and "Board Committees," respectively. Such information is incorporated by reference as if fully set forth herein.

Information regarding our executive officers can be found in Item 1 - Business – Executive Officers of Integrys Energy Group.

We have a Code of Conduct, which serves as our Code of Business Conduct and Ethics. The Code of Conduct applies to all of our directors, officers, and employees, including the Chief Executive Officer, Chief Financial Officer, Corporate Controller, and any other persons performing similar functions. We have also adopted Corporate Governance Guidelines.

Our Code of Conduct, Corporate Governance Guidelines, and charters of our board committees may be accessed on our website at www.integrysgroup.com by selecting "Investors," then selecting "Corporate Governance," then selecting "Governance Documents." Our Code of Conduct is available in print, without charge, to any shareholder who requests it from the Company's Secretary. Amendments to, or waivers from, the Code of Conduct will be disclosed on the website within the prescribed time period.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item regarding compensation paid to our directors and our "named executive officers" in 2013 can be found in our Proxy Statement under the captions "Director Compensation," "Executive Compensation," and "Compensation Risk Assessment." Such information is incorporated by reference as if fully set forth herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this Item regarding our principal security holders and the security holdings of our directors and executive officers can be found in our Proxy Statement under the caption "Ownership of Voting Securities – Beneficial Ownership." Such information is incorporated by reference as if fully set forth herein.

Information required by this Item regarding our equity compensation plans can be found in our Proxy Statement under the caption "Ownership of Voting Securities – Equity Compensation Plan Information." Such information is incorporated by reference as if fully set forth herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this Item regarding our related person transactions and director independence can be found in our Proxy Statement under the captions "Election of Directors – Related Person Transaction Policy" and "Election of Directors – Director Independence," respectively. Such information is incorporated by reference as if fully set forth herein.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For a summary of the fees billed to us (including our subsidiaries) by Deloitte & Touche LLP for professional services performed for 2013 and 2012 and the Audit Committee's preapproval policies and procedures, please see our Proxy Statement under the caption "Board Committees – Audit Committee." Such information is incorporated by reference as if fully set forth herein.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Documents filed as part of this report:

(1) Consolidated Financial Statements included in Part II at Item 8 above:

Financial Statement Schedules.

(2) The following financial statement schedules are included in Part IV of this report. Schedules not included herein have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(3) List of all exhibits, including those incorporated by reference.

See Exhibit Index.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 27, 2014.

INTEGRYS ENERGY GROUP, INC.
(Registrant)

By: /s/ Charles A. Schrock
Charles A. Schrock
Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 27, 2014.

Signature	Title
William J. Brodsky *	Director
Albert J. Budney, Jr. *	Director
Ellen Carnahan *	Director
Michelle L. Collins *	Director
Kathryn M. Hasselblad-Pascale *	Director
John W. Higgins *	Director
Paul W. Jones *	Director
Holly Keller Koeppel *	Director
Michael E. Lavin *	Director
William F. Protz, Jr. *	Director
Charles A. Schrock *	Director and Chairman
/s/ Charles A. Schrock Charles A. Schrock	Chairman and Chief Executive Officer (principal executive officer)
/s/ James F. Schott James F. Schott	Vice President and Chief Financial Officer (principal financial officer)
/s/ Linda M. Kallas Linda M. Kallas	Vice President and Controller (principal accounting officer)
* By: /s/ Linda M. Kallas Linda M. Kallas	Attorney-in-Fact

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SCHEDULE I - CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
INTEGRYS ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. STATEMENTS OF INCOME

Year Ended December 31 (Millions, except per share data)	2013	2012	2011
Operating expense	$8.2	$6.0	$5.9
Operating loss	(8.2)	(6.0)	(5.9)
Equity earnings from subsidiaries	397.1	332.4	275.5
Miscellaneous income	18.5	21.2	24.2
Interest expense	52.1	50.0	52.2
Other income	363.5	303.6	247.5
Income before taxes	355.3	297.6	241.6
Provision for income taxes	8.3	6.5	14.7
Net income from continuing operations	347.0	291.1	226.9
Discontinued operations from Parent Company, net of tax	0.6	1.4	(0.2)
Discontinued operations from subsidiaries, net of tax	4.2	(11.1)	0.7
Net income attributed to common shareholders	$351.8	$281.4	$227.4
Average shares of common stock			
Basic	79.5	78.6	78.6
Diluted	80.1	79.3	79.1
Earnings (loss) per common share (basic)			
Net income from continuing operations	$4.37	$3.70	$2.89
Discontinued operations, net of tax	0.06	(0.12)	—
Earnings per common share (basic)	$4.43	$3.58	$2.89
Earnings (loss) per common share (diluted)			
Net income from continuing operations	$4.33	$3.67	$2.87
Discontinued operations, net of tax	0.06	(0.12)	—
Earnings per common share (diluted)	$4.39	$3.55	$2.87

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

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B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (Millions)	2013	2012	2011
Net income attributed to common shareholders	351.8	281.4	227.4
Other comprehensive income, net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of $ - million, $0.1 million, and $(0.3) million, respectively	0.6	(0.1)	0.3
Reclassification of net (gains) losses to net income, net of tax of $2.0 million, $(1.0) million, and $0.2 million, respectively	(0.9)	2.1	1.1
Cash flow hedges, net	(0.3)	2.0	1.4
Defined benefit plans			
Pension and other postretirement benefit adjustments arising during period, net of tax of $ - million, $(0.9) million, and $(0.7) million, respectively	1.1	0.9	—
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.9 million, $0.4 million, and $0.1 million, respectively	(0.5)	(0.1)	0.2
Defined benefit pension plans, net	0.6	0.8	0.2
Other comprehensive income (loss) from subsidiaries, net of tax	17.4	(1.2)	0.6
Other comprehensive income, net of tax	17.7	1.6	2.2
Comprehensive income attributed to common shareholders	369.5	283.0	229.6

The accompanying notes to Integrys Energy Group's parent company financial statements are an integral part of these statements.

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C. BALANCE SHEETS

At December 31 (Millions)	2013	2012
Assets		
Cash and cash equivalents	$0.3	$2.6
Accounts receivable from related parties	32.2	32.2
Interest receivable from related parties	4.1	4.7
Deferred income taxes	0.6	1.0
Notes receivable from related parties	84.9	34.5
Current portion of long-term notes receivable from related parties	10.0	72.0
Other current assets	47.8	39.4
Current assets	179.9	186.4
Total investments in subsidiaries, at equity	4,268.5	3,839.3
Notes receivable from related parties	224.3	171.2
Property and equipment, net of accumulated depreciation of $1.4 and $1.2, respectively	4.5	4.7
Receivables from related parties	18.3	17.3
Deferred income taxes	22.3	28.1
Other long-term assets	43.9	31.7
Total assets	$4,761.7	$4,278.7
Liabilities and Equity		
Short-term notes payable to related parties	$165.7	$258.0
Short-term debt	123.2	208.4
Current portion of long-term debt	100.0	—
Accounts payable to related parties	0.9	1.0
Interest payable to related parties		