INTEGRYS ENERGY GROUP, INC.
Form 10-K
March 02, 2015

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, 2014
OR

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

For the transition period from ________________ to ___________________

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

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 [ ]

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.

$5,656,939,310 as of June 30, 2014

Number of shares outstanding of each class of common stock, as of February 25, 2015

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

INTEGRYS ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2014

TABLE OF CONTENTS

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

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, 2014, and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting the regulated businesses;
- Federal and state legislative and regulatory changes, including deregulation and restructuring of the electric and natural gas utility industries, financial reform, health care reform, energy efficiency mandates, reliability standards, pipeline integrity and safety standards, and changes in tax and other laws and regulations to which we and our subsidiaries are subject;
- The possibility that the proposed merger with Wisconsin Energy Corporation does not close (including, but not limited to, due to the failure to satisfy the closing conditions), disruption from the proposed merger making it more difficult to maintain our business and operational relationships, and the risk that unexpected costs will be incurred during this process;
- The risk of terrorism or cyber security attacks, including the associated costs to protect our assets and respond to such events;
- The risk of failure to maintain the security of personally identifiable information, including the associated costs to notify affected persons and to mitigate their information security concerns;
- The timely completion of capital projects within estimates, as well as the recovery of those costs through established mechanisms;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The impact of unplanned facility outages;
- The risks associated with changing commodity prices, particularly natural gas and electricity, and the available sources of fuel, natural gas, and purchased power, including their impact on margins, working capital, and liquidity requirements;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer energy use, customer growth, and our ability to adequately forecast energy use for our customers;
- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards;
- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims;
- Changes in credit ratings and interest rates caused by volatility in the financial markets and actions of rating agencies and their impact on our and our subsidiaries' liquidity and financing efforts;
- The ability to retain market-based rate authority;
- The effects, extent, and timing of competition or additional regulation in the markets in which our subsidiaries operate;
- The risk of financial loss, including increases in bad debt expense, associated with the inability of our and our subsidiaries' counterparties, affiliates, and customers to meet their obligations;
- The ability to use tax credit, net operating loss, and/or charitable contribution carryforwards;

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

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

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. 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 ITF, PDI, the Integrys Energy Group holding company, and the PELLC holding company. 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 28, 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 an energy holding company headquartered in Chicago, Illinois. We were incorporated in Wisconsin in 1993. Our wholly owned subsidiaries provide regulated natural gas and electricity, as well as nonregulated renewable energy and compressed natural gas products and services. In addition, we have a 34% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2014, we had four reportable segments with continuing operations and one reportable segment that only contained the discontinued operations related to IES's retail energy business. Our reportable segments are discussed below. In June 2014, we entered into an Agreement and Plan of Merger with Wisconsin Energy Corporation. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information on this transaction.

Facilities

For information regarding our facilities, see Item 2, Properties. For our plant asset book values, see Note 7, 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. NATURAL GAS UTILITY OPERATIONS

Our natural gas utility segment includes the natural gas utility operations of MERC, MGU, NSG, PGL, and WPS. For MERC and MGU, both Delaware corporations, we acquired their existing natural gas distribution operations in Minnesota and Michigan in July 2006 and April 2006, respectively. 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 natural gas utilities provide service to approximately 1.7 million residential, commercial and industrial, transportation, and other customers. Our customers are located in Chicago and the northern suburbs of Chicago, northeastern Wisconsin, various cities and communities throughout Minnesota, the southern portion of lower Michigan, and Michigan's Upper Peninsula.

Natural Gas Supply

Our natural gas utilities manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value.

Our 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 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 natural gas utilities purchase additional natural gas supply on the monthly and daily spot markets.

For more information on our natural gas utility supply and transportation contracts, see Note 17, Commitments and Contingencies.

Our natural gas utilities own two storage fields (Manlove Field in central Illinois and Partello in Michigan) 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 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 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 natural gas utilities when negotiating new agreements for transportation and storage services. Our 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 Manlove Field and a natural gas pipeline system that connects Manlove Field to Chicago and 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. 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 tables below are 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)	2014	2013	2012
Beginning Balance, January 1	5,143	5,240	5,261
Injections	3,104	7,000	7,000
Withdrawals	(6,028)	(7,097)	(7,021)
Ending Balance, December 31	2,219	5,143	5,240

(Millions)	2014	2013	2012
Natural gas hub service fees	$1.8	$4.3	$3.9

Our natural gas utilities had adequate capacity to meet all firm natural gas demand obligations during 2014 and expect to have adequate capacity to meet all firm demand obligations during 2015. Our natural gas utilities' forecasted design peak-day throughput is 4,020 MDth for the 2014 through 2015 heating season.

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

(MDth)	2014	2013	2012
Natural gas purchases	260,532	232,007	184,188
Natural gas purchases for electric generation	1,655	2,246	2,215
Customer-owned natural gas received	205,033	191,101	176,598
Underground storage, net	(12,692)	6,123	2,749

Hub fuel in kind *	80	179	179
Liquefied petroleum gas (propane)	71	1	1
Owned storage cushion injection	(1,138)	(1,097)	(1,097)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted-for natural gas	(7,876)	(12,992)	(8,037)
Total	445,665	417,568	356,796

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

Regulatory Matters

Our 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 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 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 (sometimes referred to as the "natural gas charge") and, 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 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 Pipeline and Hazardous Materials Safety Administration and the state commissions are responsible for monitoring and enforcing requirements governing our 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 natural gas utility subsidiaries are required to provide service and grant credit (with applicable deposit requirements) to customers within their service territories. Our natural gas utilities are generally not allowed to discontinue service during winter moratorium months to residential heating 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 25, Regulatory Environment, for information regarding rate cases, decoupling mechanisms, bad debt recovery mechanisms, and other cost recovery mechanisms at our 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 2014, the natural gas utility segment recorded approximately 66% of its revenues in January, February, March, November, and December.

Competition

Although our natural gas retail rates are regulated by various commissions, the 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 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 natural gas utilities all offer natural gas transportation service, and certain of our 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 natural gas utilities' distribution systems to transport the natural gas to their facilities. Our 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 little impact on our 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 natural gas utility operations vary significantly over time due to volatility in levels of natural gas inventories and the price of natural gas. Our 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 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. ELECTRIC UTILITY OPERATIONS

For the periods presented in this Annual Report on Form 10-K, the electric utility segment included the electric utility operations of WPS and the electric utility operations of UPPCO until its sale in 2014. WPS, a Wisconsin corporation, began operations in 1883. In August 2014, we sold all of the stock of UPPCO. See Note 4, Dispositions, for more information.

The electric utility operations of WPS provide service to approximately 450,000 residential, commercial and industrial, wholesale, and other customers. WPS's customers are located in northeastern Wisconsin and Michigan's Upper Peninsula. Wholesale electric service is provided to various customers, including municipal utilities, electric cooperatives, energy marketers, other investor-owned utilities, and municipal joint action agencies. In 2014, retail electric revenues accounted for 87.3% of total electric revenues, while wholesale electric revenues accounted for 12.7% of total electric revenues.

Electric Supply

WPS is a member of MISO, a FERC-approved, independent, nonprofit organization, which operates a financial and physical electric wholesale market in the Midwest. WPS offers generation and bids customer load into the MISO market. MISO evaluates WPS's and all other market participants' energy offers into, and subsequent withdrawals from, the transmission system to economically and reliably dispatch generation to serve load. 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 WPS's electric utility supply were as follows:

(Millions) Energy Source (kilowatt-hours)	2014	2013	2012
Company-owned generation units			
Coal	7,130.2	8,723.1	7,390.1
Natural gas, fuel oil, and tire-derived fuel [(1)]	1,705.8	1,539.4	175.9
Wind	326.1	309.7	330.6
Hydro	423.6	231.0	176.4
Total company-owned generation units	9,585.7	10,803.2	8,073.0
Power purchase contracts [(2)]			
Nuclear (Kewaunee Power Station) [(3)]	—	2,808.3	2,655.5
Hydro	355.8	553.8	392.6
Natural gas (Fox Energy Center) [(4)]	—	395.1	2,892.6
Wind	221.5	209.1	220.1
Other	1,506.8	674.0	1,580.5
Total power purchase contracts	2,084.1	4,640.3	7,741.3
Purchased power from MISO	2,960.3	600.3	584.7
Total purchased power	5,044.4	5,240.6	8,326.0
Opportunity sales			
Sales to MISO	(286.8)	(1,591.4)	(1,799.5)
Net sales to other	(303.7)	(407.8)	(128.4)
Total opportunity sales	(590.5)	(1,999.2)	(1,927.9)
Total electric utility supply	14,039.6	14,044.6	14,471.1

(1) Reflects the purchase of Fox Energy Company LLC in March 2013. See Note 3, Acquisitions, for more information.

(2) See Note 17, Commitments and Contingencies, for more information on power purchase obligations.

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

(4) 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.

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 14.8% reserve margin requirement from January 1, 2015, through May 31, 2015, and 14.3% for the remainder of 2015. The MPSC does not have minimum guidelines for future supply reserves.

WPS had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2014. In 2015, WPS expects to have adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations, including the minimum planning reserve margin requirements.

Fuel Costs

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

Fuel Type	2014	2013	2012
Coal	$2.53	$2.57	$2.52
Natural gas	5.17	3.47	3.97
Fuel oil	21.15	22.16	26.45

Coal Supply

Coal is the primary fuel source for WPS's electric generation facilities. WPS's 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 coal for the jointly owned Weston 4 plant, and Dairyland Power Cooperative reimburses WPS for their share of the coal costs. Wisconsin Power and Light Company purchases coal for the jointly owned Edgewater and Columbia plants, and WPS reimburses them for its share of the coal costs. At December 31, 2014, WPS had coal transportation contracts in place for 100% of its 2015 coal transportation requirements. See Note 17, Commitments and Contingencies, for more information on coal purchases and coal deliveries under contract.

Regulatory Matters

WPS's retail electric rates are regulated by the PSCW and the MPSC. The FERC regulates WPS's wholesale electric rates. WPS 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.

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. 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. See Note 1(f), Revenues and Customer Receivables, for more information. WPS charges formula-based rates, as approved by the FERC, for the sale of electricity to its wholesale customers.

See Note 25, Regulatory Environment, for more information regarding WPS's rate cases and decoupling mechanisms.

Hydroelectric Licenses

WPS 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 are generally higher during the summer months due to the air conditioning requirements of our customers.

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 better match the cost of electricity to each class of customer by reducing or eliminating rate subsidies among different ratepayer classes.

Michigan electric energy markets are open to competition, subject to certain limitations. Since 2012, alternate energy suppliers entered our service territories in the Upper Peninsula of Michigan, creating an active competitive market resulting in some lost load.

D. INTEGRYS ENERGY SERVICES

We sold the nonregulated retail energy business of IES on November 1, 2014. PDI, the energy asset business that was formerly a part of IES, remains but has been reclassified to the holding company and other segment, as PDI's operations are not material to the consolidated company.

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 10, 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, the operations of ITF, and the operations of PDI, the energy asset business that was formerly a part of IES. In addition, any nonutility activities at IBS, MERC, MGU, NSG, PGL, and WPS are included in this segment.

ITF designs, builds, maintains, owns, and/or operates compressed natural gas fueling stations in multiple states. In addition, ITF manufactures its own compressor package which includes its proprietary method of compressing natural gas.

PDI invests in distributed renewable projects, primarily solar, and owns a natural gas-fired cogeneration facility in Wisconsin, known as the Combined Locks Energy Center. Consistent with this business's strategy and focus on renewable energy projects, it is pursuing the sale of the Combined Locks Energy Center. For more information, see Note 4, Dispositions.

Fuel Supply for Generation Facilities

PDI's natural gas-fired facility is subject to market price volatility and is dispatched to produce energy only when it is economical to do so. This facility is classified as held for sale. See Note 4, Dispositions, for more information. PDI's renewable energy facilities 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.

G. ENVIRONMENTAL MATTERS

See Note 17, 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, 2014, our consolidated subsidiaries had the following employees:

	Number of Full-Time Employees	Total Number of Employees	Percentage of Total Employees Covered by Collective Bargaining Agreements

WPS	1,276	1,333	69	%
PGL	1,302	1,302	73	%
IBS	1,230	1,266	—	%
MERC	215	220	19	%
NSG	170	171	72	%
MGU	155	158	69	%
ITF	124	125	—	%
Total	4,472	4,575	47	%

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

Union	Subsidiary	Contract Expiration Date
Local 12295 of the United Steelworkers of America, AFL CIO CLC	MGU	January 15, 2017
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 15, 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

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.

Risks Related to Our Business

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

Our 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. In addition, IBS has various capital projects which are primarily related to the development of software applications used to support our utilities.

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 commission-approved projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, the applicable commission may deem the additional capital costs as imprudent and disallow recovery of them through rates.

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.

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. Potential breakdown or failure may occur due to storms; catastrophic events (explosions, fires, tornadoes, floods, etc.); 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/or labor; and performance below expected levels. These events could lead to substantial financial losses. Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems. Unplanned outages at our power plants may reduce our revenues or may require us to incur significant costs by forcing us to operate our higher cost electric generators or purchase replacement power to satisfy our obligations. Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses.

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.

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;
- 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 our 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 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 within our service areas;
- Weather conditions; and

- Our customers' continued focus on energy efficiency and ability to meet their own energy needs.

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 (including greenhouse gas 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.

Future regulation may 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. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could 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. If generation facility owners in the Midwest, including WPS, are forced to retire a significant number of older coal-fired generation facilities, a potential reduction in the region's capacity reserve margin below acceptable risk levels could result. This could 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.

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.

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.

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

The FERC has authorized WPS to sell electricity in the wholesale market at market prices. WPS must file an updated market power analysis with the FERC at least every three years to demonstrate it 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 WPS possesses market power, that WPS is not charging just and reasonable rates, or that WPS has not complied with the rules required in order to maintain market-based rates, the FERC may require WPS to sell power at a price based upon the costs incurred in producing the power, or otherwise revoke or rescind its authority in that market. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates WPS may receive, or otherwise by any revocation or rescission of such authority.

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, 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.

We are dependent on coal for much of our electric generating capacity. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be forced to reduce generation at our coal-fired units and replace this lost generation through additional power purchases in the MISO market. There is no guarantee that we would be able to fully recover any increased costs in rates. Our electric generation frequently exceeds our customer load. When this occurs, we generally sell the excess generation into the MISO market. If we are unable to run our lower cost units, we may lose the ability to engage in these opportunity sales, which may adversely affect our results of operations.

Our customers may experience financial problems. Financially distressed customers might default on their obligations to us or reduce their future use of our products and services. We cannot assure that such defaults or reductions in use of our products and services will not have a material adverse impact on our business, financial position, results of operations, or cash flows.

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

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits, net operating losses, and charitable contribution deductions available under the applicable tax codes. We have not fully used the allowed tax credits, net operating losses, and charitable contribution deductions in our previous tax filings. We may not be able to fully use the tax credits, net operating losses, and charitable contribution deductions available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit their use. In addition, any future disallowance of some or all of those tax credit, net operating loss, or charitable contribution 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.

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.

Risks Related to the Proposed Merger with Wisconsin Energy Corporation (Wisconsin Energy)

Failure to complete the merger could negatively affect our share price and our future businesses and financial results.

Completion of the merger is not assured and is subject to risks, including the risks that approval by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, our ongoing business and financial results may be adversely affected and we will be subject to several risks, including the following:

- We may have to pay certain significant costs relating to the merger without receiving the benefits of the merger;
- The attention of our management may have been diverted to the merger rather than to our own operations and the pursuit of other opportunities that could have been beneficial to us;
- There may have been a potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;

- We would have been subject to certain restrictions on the conduct of our business which may have prevented us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger was pending;
- Our share price may decline to the extent that the current market price reflects an assumption by the market that the merger will be completed;
- There may be adverse consequences to our business and our relations with governmental agencies arising out of our efforts to obtain regulatory approvals for the merger if such efforts are unsuccessful;
- We may suffer adverse business consequences relating to the uncertainty caused by the potential merger, including a potential loss of customers; and
- We may be subject to litigation related to any failure to complete the merger.

In addition, ten purported class action and/or derivative lawsuits were filed against us, members of our board of directors, and
Wisconsin Energy. These lawsuits sought, among other things, an injunction prohibiting the consummation of the merger. As disclosed in our Form 8-K filed with the SEC on November 12, 2014, counsel for the parties to each of these lawsuits entered into a memorandum of understanding on November 12, 2014, pursuant to which, among other things, we and Wisconsin Energy agreed to make the disclosures concerning the merger that were set forth in that Form 8-K. The memorandum of understanding further provides for the dismissal with prejudice of all remaining actions and the release of any and all claims, including derivative claims, concerning the merger, subject to court approval after notice to the proposed class of our shareholders. All actions are stayed pending execution of definitive settlement documentation and a decision by the relevant courts regarding approval of the proposed settlement. While we believe the relevant courts will approve the parties' proposed settlement, we cannot make any assurances as to such approval. As discussed further below, the courts' failure to approve such settlement could result in the resumption of litigation seeking, among other things, to prevent the consummation of the merger.

The occurrence of any of these events individually or in combination could negatively affect the trading price of our common stock and our future business and financial results.

We and Wisconsin Energy may be unable to obtain the regulatory approvals required to complete the merger or, in order to do so,
we and Wisconsin Energy may be required to comply with material restrictions or conditions that may negatively affect the combined company after the merger is completed or cause us to abandon the merger.

Completion of the merger is contingent upon, among other things, the receipt of all required regulatory approvals. For us, this consists of filings with and approvals of the New York Stock Exchange (NYSE), notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the Federal Communications Commission (FCC), notice to and approval of the ICC and the MPSC, and, to the extent required, notice to and approval of the MPUC. In the case of Wisconsin Energy, this consists of filings with and approvals of the NYSE, notice to, and the consent and approval of, the FERC, pre-approvals of license transfers with the FCC, notice to and approval of the PSCW, the ICC, and the MPSC, and, if required or advisable, the MPUC. We are a party to a contested settlement agreement with the MPSC staff and all but one of the parties in the MPSC approval docket. The settling parties agree that the MPSC should grant approval of the merger contingent on additional transactions, including the sale of the Presque Isle facility currently owned by Wisconsin Energy, as well as the Michigan electric distribution assets of Wisconsin Energy and WPS, to UPPCO. The asset sales require additional approvals, including the MPSC, PSCW, FERC, FCC, and Committee on Foreign Investment in the United States, as well as the requirements of the Hart-Scott-Rodino Act. We can provide no assurance that all required regulatory authorizations, approvals, or consents will be obtained, or that they will not contain terms, conditions, or restrictions that would be detrimental to the combined company after completion of the merger.

Uncertainties associated with the merger may cause a loss of management personnel and other key employees which could adversely affect the future business and operations of the combined company following the merger.

We and Wisconsin Energy are dependent on the experience and industry knowledge of our officers and other key employees to execute our respective business plans. The combined company's success after the merger will depend in part upon its ability to retain key management personnel and other key employees of us and Wisconsin Energy. Current and prospective employees of us and Wisconsin Energy may experience uncertainty about their future roles with the combined company following the merger, which may materially adversely affect the ability of each of us to attract and retain key personnel during the pendency of the merger. Accordingly, no assurance can be given that the combined company will be able to retain key management personnel and other key employees of us and Wisconsin Energy.

We are subject to various uncertainties and contractual restrictions while the merger is pending that could adversely affect our financial results.

Uncertainty about the effect of the merger on employees, suppliers, and customers may have an adverse effect on us. These uncertainties may impair our ability to attract, retain, and motivate key personnel until the merger is completed and for a period of time thereafter. Employee retention and recruitment may be particularly challenging prior to completion of the merger, as current and prospective employees may experience uncertainty about their future roles with the combined company. Uncertainties could also cause customers, suppliers, and others who deal with us to seek changes to our existing business relationships.

The pursuit of the merger and the preparation for the integration of us and Wisconsin Energy may place a significant burden on management and internal resources. Any significant diversion of management's attention away from ongoing business, and any difficulties encountered in the transition and integration process, could affect our financial results and/or the financial results of the combined company.

In addition, the merger agreement restricts us, without Wisconsin Energy's consent, from making certain acquisitions and dispositions and taking other specified actions while the merger is pending. These restrictions may prevent us from pursuing attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

Because the merger consideration is fixed and the market price of shares of Wisconsin Energy common stock will fluctuate, our shareholders cannot be sure of the value of the merger consideration they will receive.

Upon completion of the merger, each outstanding share of our common stock will be converted into the right to receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash. Based on the closing price of Wisconsin Energy common stock on June 20, 2014, the last trading day before the public announcement of the merger, the aggregate value of the merger consideration was approximately $5.8 billion. The number of shares of Wisconsin Energy common stock to be issued pursuant to the merger agreement for each share of our common stock is fixed and will not change to reflect changes in the market price of Wisconsin Energy or our common stock. Because the exchange ratio will not be adjusted to reflect any changes in the market value of either company's common stock, the market value of the Wisconsin Energy common stock issued in connection with the merger and our common stock surrendered in connection with the merger, may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from, among other things, changes in the business, operations, or prospects of Wisconsin Energy or us prior to or following the merger; litigation or regulatory considerations; general business, market, industry, or economic conditions; and other factors both within and beyond the control of Wisconsin Energy and us. Neither we nor Wisconsin Energy is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The merger agreement precludes us from pursuing alternatives to the merger.

Under the merger agreement, we are restricted from pursuing or entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, we are restricted from, among other things, soliciting, initiating, knowingly encouraging, inducing, or knowingly facilitating a competing acquisition proposal from any person. These provisions would discourage a third party that may have an interest in acquiring all or a significant part of us from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger. As a result of these restrictions, we cannot enter into an agreement with respect to a more favorable alternative transaction, prior to the termination of the merger agreement, without incurring potentially significant liability to Wisconsin Energy.

If completed, the merger may not achieve its intended results, and we and Wisconsin Energy may be unable to successfully integrate our operations.

We and Wisconsin Energy entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, accretion to the combined company's earnings per share in the first full calendar year following completion of the merger. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including the following:

- Whether our business and the business of Wisconsin Energy can be integrated in an efficient and effective manner;
- Whether U.S. federal and state public utility authorities, whose approval is required to complete the merger, impose conditions on the completion of the merger which have an adverse effect on the combined company;
- General market and economic conditions;
- General competitive factors in the marketplace; and
- Higher than expected costs required to achieve the anticipated benefits of the merger.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees; the disruption of each company's ongoing businesses, processes, and systems; or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements. Any of these could adversely affect the combined company's ability to achieve the anticipated benefits of the merger. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of their realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results, and prospects.

Pending litigation against us and Wisconsin Energy that is the subject of a proposed settlement could nevertheless result in an injunction preventing completion of the merger, the payment of damages in the event the merger is completed, and/or may adversely affect the combined company's business, financial condition, or results of operations following the merger.

In connection with the merger, purported shareholders of ours filed putative stockholder class action and/or derivative lawsuits against us, our directors, and Wisconsin Energy seeking to enjoin the merger. As discussed above, those lawsuits are currently stayed pending finalization of proposed settlement documentation and a decision by the relevant courts regarding approval of the proposed settlement. Nevertheless, one of the conditions to the closing of the merger is that no law or judgment issued by any court of competent jurisdiction shall be in effect that, and no suit, action, or other proceeding shall be pending before any governmental entity in which such governmental entity seeks to impose any legal restraint that, prevents, makes illegal, or prohibits the consummation of the merger. Consequently, if the proposed settlement is not approved, the litigation may recommence and one of the plaintiffs may be successful in obtaining an injunction prohibiting us or Wisconsin Energy from consummating the merger on the agreed-upon terms. In that event, the injunction may prevent the merger from being completed within the expected timeframe, or at all. Furthermore, if the proposed settlement is not approved and defendants are not able to resolve these lawsuits, the lawsuits could result in substantial costs to us, including any costs associated with the indemnification of directors. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition, or results of operations.

Delays in completing the merger may substantially reduce the expected benefits of the merger.

Satisfying the conditions to, and completion of, the merger may take longer than, and could cost more than, we and Wisconsin Energy expect. Any delay in completing or any additional conditions imposed in order to complete the merger may materially adversely affect the benefits that we and Wisconsin Energy expect to achieve from the merger and the integration of our respective businesses. In addition, we or Wisconsin Energy may terminate the merger agreement if the merger is not completed by June 22, 2015, except that such date may be extended to December 22, 2015 if the only unsatisfied conditions to the completion of the merger are those regarding the receipt of required regulatory approvals.

We will incur substantial transaction fees and costs in connection with the merger.

We and Wisconsin Energy expect to incur non-recurring expenses totaling approximately $60 million in connection with the merger. Additional unanticipated costs may be incurred in the course of the integration of our businesses. We cannot be certain that the elimination of duplicative costs or the realization of other efficiencies related to the integration of the two businesses will offset the transaction and integration costs in the near term, or at all.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A. REGULATED

Natural Gas Facilities

At December 31, 2014, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,500 miles of natural gas distribution mains,
- Approximately 1,000 miles of natural gas transmission mains,
- Approximately 1.3 million natural gas lateral services,
- 296 natural gas distribution and transmission gate stations,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.2 billion-cubic-foot underground natural gas storage field located in central Illinois,*
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois, and
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquified petroleum gas.

* PGL owns and operates this reservoir 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, 2014:

Type	Name	Location	Primary Fuel	Rated Capacity (Megawatts) (1)	
Steam	Columbia Units 1 and 2	Portage, Wisconsin	Coal	353.0	(2)
	Edgewater Unit 4	Sheboygan, Wisconsin	Coal	93.8	(2)
	Pulliam (4 units)	Green Bay, Wisconsin	Coal	325.4	(3)
	Weston Units 1, 2, and 3	Marathon County, Wisconsin	Coal	450.6	(3)
	Weston Unit 4	Marathon County, Wisconsin	Coal	372.8	(2)
Total Steam				1,595.6	
Combustion Turbine and Diesel	Fox Energy Center	Kaukauna, Wisconsin	Natural Gas	551.6	
	De Pere Energy Center	De Pere, Wisconsin	Natural Gas	159.4	
	Juneau #31	Adams County, Wisconsin	Distillate Fuel Oil	6.2	(4)
	Pulliam #31	Green Bay, Wisconsin	Natural Gas	79.9	
	West Marinette #31	Marinette, Wisconsin	Natural Gas	38.4	
		Marinette, Wisconsin	Natural Gas	38.4	

	West Marinette #32				
	West Marinette #33	Marinette, Wisconsin	Natural Gas	73.6	
	Weston #31	Marathon County, Wisconsin	Natural Gas	12.3	
	Weston #32	Marathon County, Wisconsin	Natural Gas	21.9	
Total Combustion Turbine and Diesel				981.7	
Total Hydroelectric	Various	Wisconsin and Michigan	Hydro	60.8	(5)
Wind	Lincoln	Wisconsin	Wind	0.9	
	Crane Creek	Iowa	Wind	21.0	
Total Wind				21.9	
Total System				2,660.0	

(1) Based on capacity ratings for summer 2015, which can differ from nameplate capacity, especially on wind projects. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(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, the Weston 1, Pulliam 5, and Pulliam 6 generating units will be retired early, in June 2015. These units have an aggregate generating capacity of 166.9 megawatts (based on summer 2015 capacity ratings). Weston 2 is also part of this EPA Consent Decree; however, it will not be retired but rather will operate on natural gas starting in June 2015. See Note 17, 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 8.7 megawatts, and WPS's share of capacity for Petenwell is 10.5 megawatts.

As of December 31, 2014, our electric utility owned approximately 21,900 miles of electric distribution lines located in Michigan and Wisconsin and 124 electric distribution substations.

General

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

B. HOLDING COMPANY AND OTHER

The following table summarizes information on the energy asset facilities owned by PDI and the compressed natural gas fueling stations owned by ITF as of December 31, 2014:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) [1]	
PDI					
Combined Cycle	Combined Locks	Combined Locks, Wisconsin	Natural Gas	45.5	(2)
Solar	Various	Various States	Solar Irradiance	47.3	(3)
				Length of Pipeline (Miles)	
Landfill Gas Transportation	LGS	Brazoria County, Texas	N/A	33	
				Number of Locations	
ITF					
Compressed Natural Gas (CNG)	Various	Various States	N/A	38	(4)

(1) Based on capacity ratings for summer 2015.

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

(3)

The solar facilities consist of distributed solar projects ranging from 0.1 to 4.5 megawatts in size. Some of the solar facilities are wholly owned by subsidiaries of PDI and others are owned by INDU Solar Holdings, LLC, which is jointly owned by PDI and Duke Energy Generation Services. PDI's portion of solar capacity owned by INDU Solar Holdings, LLC, is 9.8 megawatts and is included in the total capacity listed.

(4) The CNG fueling stations consist of 20 stations that are wholly owned and operated by ITF. ITF operates 16 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 two stations that are 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.

ITEM 3. LEGAL PROCEEDINGS

Since the June 23, 2014 announcement of the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy), we and our board of directors, along with Wisconsin Energy, were named defendants in ten class action lawsuits and/or derivative complaints brought by purported Integrys Energy Group shareholders challenging the proposed merger. Two lawsuits were filed in the Circuit Court of Milwaukee County, Wisconsin (the "Wisconsin Court"): Amo v. Integrys Energy Group, Inc., et al., (the "Amo Action") and Inman v. Schrock, et al., (the "Inman Action"). Three lawsuits were filed in the Circuit Court of Brown County, Wisconsin: Rubin v. Integrys Energy Group, Inc., et al.; Blachor v. Integrys Energy Group, Inc., et al.; and Albera v. Integrys Energy Group, Inc., et al. (together with the Amo and Inman Actions, the "Wisconsin Actions"). Two lawsuits were filed in the Circuit Court of Cook County, Illinois: Taxman v. Integrys Energy Group, Inc., et al., and Curley v. Integrys Energy Group, Inc., et al., (the "Illinois Actions"). Three lawsuits were filed in the United States District Court for the Northern District of Illinois (the "Federal Court"): Steiner v. Budney, et al., and Collison v. Schrock, et al., (the "Steiner and Collison Actions"); and Tri-State Joint Fund v. Integrys Energy Group, Inc., et al. (the "Tri-State Action").

Each of the Wisconsin and Illinois Actions was either dismissed or consolidated with the Amo Action, and, with the exception of the Inman plaintiff, whose action was consolidated after the fact, the plaintiffs in the Wisconsin Actions joined Plaintiff Amo in filing an amended complaint on October 3, 2014. The Collison Action was consolidated with the Steiner Action.

The Wisconsin Actions and Steiner and Collison Actions allege, among other things, that members of our board breached their fiduciary duties in connection with the proposed transaction, that the merger agreement involves an unfair price, that it was the product of an inadequate sales process, that it contains unreasonable deal protection devices that purportedly preclude competing offers, that the members of our board were unjustly enriched at our expense, and that the preliminary joint proxy statement/prospectus omits material information. The complaints further variously allege that we, Wisconsin Energy, and/or its acquisition subsidiaries aided and abetted the purported breaches of fiduciary duty. The plaintiffs in these lawsuits seek, among other things, (i) a declaration that the merger agreement was entered into in breach of our directors’ fiduciary duties, (ii) an injunction enjoining our board from consummating the merger, (iii) an order directing our board to exercise its duty to obtain a transaction that is in the best interests of Integrys Energy Group’s shareholders, (iv) an order granting the class members any benefits allegedly improperly received by the defendants, (v) a rescission of the merger or damages, in the event that it is consummated, (vi) disgorgement of benefits or compensation obtained as a result of the purported breaches of fiduciary duty, and/or (vii) an order directing additional disclosure regarding the merger. The Tri-State Action seeks to enjoin the proposed transaction and alleges that we, our board, Wisconsin Energy, and Gale E. Klappa (the Wisconsin Energy Chief Executive Officer) violated Sections 14(a) and 20(a) of the 1934 Securities Exchange Act and Rule 14a-9 promulgated thereunder. It alleges, among other things, that the registration statement misrepresented or omitted material facts, including material information about the allegedly unfair and conflicted sales process, the inadequate consideration offered in the proposed transaction, and our actual intrinsic value.

On November 12, 2014, our counsel, our board of directors, Mr. Klappa, and Wisconsin Energy entered into a memorandum of understanding ("MOU") with counsel for plaintiffs in the Amo, Steiner and Collison, and Tri-State Actions pursuant to which we and Wisconsin Energy agreed to make additional disclosures concerning the merger. The MOU also provides that, solely for purposes of settlement, the Wisconsin Court will certify a class consisting of all persons who were record or beneficial shareholders of ours at any time between June 23, 2014 and the consummation of the merger (the “Class”). In addition, the MOU provides that, subject to approval by the Wisconsin Court after notice to the members of the Class (the “Class Members”), the Amo, Steiner and Collison, and Tri-State Actions will be dismissed with prejudice and all claims, including derivative claims, that the Class Members may possess with regard to the merger will be released. In connection with the settlement, the plaintiffs’ counsel has expressed its intention to seek an award of attorneys’ fees and expenses. The amount of the award to the plaintiffs’ counsel will ultimately be determined by the Wisconsin and/or Federal Courts. This payment will not affect the amount of merger consideration to be received by any of our shareholders in the merger. There can be no assurance that the parties will ultimately enter into a definitive settlement agreement or that the Wisconsin Court will approve the settlement. In the absence of either event, the proposed settlement as contemplated by the MOU may be terminated.

We, our board of directors, Mr. Klappa, and Wisconsin Energy each have denied, and continue to deny, that we or they have committed or aided and abetted in the commission of any violation of law or breaches of duty or engaged in any of the alleged wrongful acts, and we, our board of directors, Mr. Klappa, and Wisconsin Energy expressly maintain that we and they diligently and scrupulously complied with fiduciary, disclosure, and other legal duties. We, our board of directors, Mr. Klappa, and Wisconsin Energy are entering into the MOU and the contemplated settlement solely to eliminate the risk, burden, and expense of further litigation. Nothing in the MOU, any settlement agreement, or any public filing shall be deemed to be an admission of the legal necessity of filing or the materiality under applicable laws of any of the additional information contained herein or in any public filing associated with the proposed settlement of the Amo, Steiner and Collison, and Tri-State Actions.

See Note 17, 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.

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:

	2014			2013		
Quarter	High	Low	Dividends	High	Low	Dividends
First	$59.83	$52.08	$0.68	$58.27	$52.55	$0.68
Second	71.35	56.46	0.68	62.75	55.39	0.68
Third	71.10	63.59	0.68	63.58	53.80	0.68
Fourth	80.88	64.63	0.68	59.74	52.70	0.68

As of the close of business on February 25, 2015, we had 23,107 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 20, Common Equity, for more information regarding restrictions on the ability of our subsidiaries to pay us dividends, as well as the dividend restrictions under the merger agreement with Wisconsin Energy Corporation (Wisconsin Energy).

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

The following table provides a summary of common stock purchases for the three months ended December 31, 2014:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
10/01/14 – 10/31/14 *	545,269	$69.95	—	—
11/01/14 – 11/30/14 *	540,562	72.59	—	—
12/01/14 – 12/31/14 *	267,547	75.64	—	—
Total	1,353,378	$72.13	—	—

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

Under the merger agreement with Wisconsin Energy, we cannot issue shares of our common stock.

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)	2014 (1) (2)	2013 (2)	2012 (2)	2011 (2)	2010 (2)
Operating revenues	$4,144.2	$3,485.5	$3,012.9	$3,324.0	$3,392.4
Net income from continuing operations	278.1	267.5	238.9	228.1	212.0
Net income attributed to common shareholders	276.9	351.8	281.4	227.4	220.9
Total assets	11,282.0	11,243.5 (3)	10,327.4	9,983.2	9,816.8
Preferred stock of subsidiary	51.1	51.1	51.1	51.1	51.1
Long-term debt (excluding current portion)	2,956.3	2,956.2	1,931.7	1,845.0	2,134.6
Average shares of common stock					
Basic	80.2	79.5	78.6	78.6	77.5
Diluted	80.7	80.1	79.3	79.1	78.0
Earnings per common share (basic)					
Net income from continuing operations	$3.43	$3.33	$3.00	$2.86	$2.70
Earnings per common share (basic)	3.45	4.43	3.58	2.89	2.85
Earnings per common share (diluted)					
Net income from continuing operations	3.41	3.30	2.98	2.84	2.68
Earnings per common share (diluted)	3.43	4.39	3.55	2.87	2.83
Dividends per common share declared	2.72	2.72	2.72	2.72	2.72
Stock price at year-end	$77.85	$54.41	$52.22	$54.18	$48.51
Book value per share	$41.49	$41.05	$38.84	$38.01	$37.57
Return on average equity	8.3 %	11.2 %	9.4 %	7.7 %	7.7 %
Number of common stock shareholders	23,511	24,908	28,425	28,993	30,352
Number of employees	4,575	4,888	4,717	4,619	4,612

(1) Includes the impact of the sale of UPPCO. In August 2014, we sold UPPCO to Balfour Beatty Infrastructure Partners LP. See Note 4, Dispositions, for more information.

(2) In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC. See Note 4, Dispositions, for more information. Due to the sale, IES's retail energy business has been reclassified to discontinued operations for all periods presented.

(3) Includes the impact of the acquisition of the Fox Energy Center in March 2013. See Note 3, Acquisitions, for more information.

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

INTRODUCTION

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

Strategic Overview

Our goal is to create long-term value for shareholders and customers through growth in our core regulated businesses.

The essential components of our business strategy are:

Maintaining and Growing a Strong Utility Base – A strong 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 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 proposed new natural gas-fueled electric generating unit to be built at the site of the Fox Energy Center in Wisconsin,
- 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, and
- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.7 billion of transmission assets at December 31, 2014. ATC plans to invest approximately $3.3 billion to $3.9 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 for 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.

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 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 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 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Natural gas utility operations	$100.2	$123.4	$93.4	(18.8)%	32.1%
Electric utility operations	163.7	110.9	107.9	47.6%	2.8%
Electric transmission investment	51.3	53.9	52.4	(4.8)%	2.9%
IES's retail operations – discontinued operations	0.4	82.5	55.1	(99.5)%	49.7%
Holding company and other operations	(38.7)	(18.9)	(27.4)	104.8%	(31.0)%
Net income attributed to common shareholders	$276.9	$351.8	$281.4	(21.3)%	25.0%
Basic earnings per share	$3.45	$4.43	$3.58	(22.1)%	23.7%
Diluted earnings per share	$3.43	$4.39	$3.55	(21.9)%	23.7%
Average shares of common stock					
Basic	80.2	79.5	78.6	0.9%	1.1%
Diluted	80.7	80.1	79.3	0.7%	1.0%

2014 Compared with 2013

The $74.9 million decrease in our earnings was driven by:

- An $82.1 million after-tax decrease in income from discontinued operations at IES. See Note 4, Dispositions, for more information.
- A $59.4 million after-tax increase in operating expenses at the utilities, excluding items directly offset in margins, driven by increases in natural gas distribution costs, depreciation and amortization expense, and electric utility maintenance.
- A $17.4 million after-tax increase in interest expense on long-term debt, driven by higher average outstanding long-term debt during 2014.
- A $13.0 million increase in income tax expense due to a remeasurement of deferred income taxes in 2014 related to the sale of IES's retail energy business.
- A $9.9 million after-tax negative year-over-year impact of the 2013 reversal of reserves recorded in 2012 against decoupling accruals at PGL and NSG. See Note 25, Regulatory Environment, for more information.
- An $8.1 million after-tax increase in operating expenses at the holding company due to transaction costs incurred in 2014 related to the proposed merger with Wisconsin Energy Corporation.

These decreases in earnings were partially offset by:

-

A $51.2 million after-tax gain on the sale of UPPCO, net of transaction costs. See Note 4, Dispositions, for more information.

- The approximate $45 million after-tax positive impact of rate orders at the utilities.

- An approximate $6 million after-tax increase in electric utility wholesale margins driven by higher prices.

- An approximate $5 million after-tax net increase in utility margins due to variances related to sales volumes, net of decoupling. A positive impact from higher sales volumes at the natural gas utilities was partially offset by a decrease in electric utility margins, driven by the sale of UPPCO at the end of August 2014.

2013 Compared with 2012

The $70.4 million increase in our earnings was driven by:

- A $41.9 million after-tax increase in income from discontinued operations. See Note 4, Dispositions, for more information.

- The approximate $30 million after-tax positive impact of rate orders at the utilities.

- An approximate $30 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.

- 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 25, 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.

- 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.

Natural Gas Utility Segment Operations

	Year Ended December 31			Change in	Change in
(Millions, except heating degree days)	2014	2013	2012	2014 Over 2013	2013 Over 2012
Revenues	$2,760.4	$2,105.0	$1,672.0	31.1 %	25.9 %
Purchased natural gas costs	1,604.4	1,046.2	775.0	53.4 %	35.0 %
Margins	1,156.0	1,058.8	897.0	9.2 %	18.0 %
Operating and maintenance expense	747.3	632.7	527.5	18.1 %	19.9 %
Depreciation and amortization expense	149.0	136.0	131.8	9.6 %	3.2 %
Taxes other than income taxes	40.9	38.2	35.6	7.1 %	7.3 %
Operating income	218.8	251.9	202.1	(13.1)%	24.6 %
Miscellaneous income	1.9	1.2	0.6	58.3 %	100.0 %
Interest expense	54.4	50.2	47.3	8.4 %	6.1 %
Other expense	(52.5)	(49.0)	(46.7)	7.1 %	4.9 %
Income before taxes	$166.3	$202.9	$155.4	(18.0)%	30.6 %
Retail throughput in therms					
Residential	1,757.9	1,663.6	1,324.8	5.7 %	25.6 %
Commercial and industrial	586.1	534.8	406.0	9.6 %	31.7 %
Other	65.2	74.0	75.3	(11.9)%	(1.7)%
Total retail throughput in therms	2,409.2	2,272.4	1,806.1	6.0 %	25.8 %
Transport throughput in therms					
Residential	284.1	252.7	204.0	12.4 %	23.9 %
Commercial and industrial	1,763.4	1,650.6	1,557.9	6.8 %	6.0 %
Total transport throughput in therms	2,047.5	1,903.3	1,761.9	7.6 %	8.0 %
Total throughput in therms	4,456.7	4,175.7	3,568.0	6.7 %	17.0 %

Weather

Average actual heating degree days	7,784	7,285	5,601	6.8 %	30.1 %
Average normal heating degree days	6,764	6,600	6,709	2.5 %	(1.6)%

Natural gas utility margins are defined as natural gas utility operating revenues less purchased natural gas costs. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There were approximate 43% and 7% increases in the average per-unit cost of natural gas sold during 2014 and 2013, respectively, which had no impact on margins.

2014 Compared with 2013

Margins

Natural gas utility segment margins increased $97.2 million, driven by:

- An approximate $38 million increase in margins related to certain riders at NSG and PGL and certain energy efficiency programs at four of our natural gas utilities. This increase was offset by an equal increase in operating expenses, resulting in no impact on earnings.

NSG and PGL recovered from their customers approximately $19 million more for environmental cleanup costs at their former manufactured gas plant sites due to higher recovery rates driven by an increase in remediation costs, net of insurance settlements received, and the impact of higher sales volumes. See Note 17, Commitments and Contingencies, for more information about the manufactured gas plant sites.

NSG and PGL recovered approximately $13 million more from their customers through their bad debt rider mechanisms, driven by higher natural gas costs in 2014, an increase in sales volumes, and rate increases.

Our natural gas utilities recovered approximately $6 million more from customers for energy efficiency programs at MERC, MGU, NSG, and PGL in 2014.

- An approximate $35 million net increase in margins due to rate orders. See Note 25, Regulatory Environment, for more information.

The rate increases at NSG and PGL, effective June 27, 2013, and updated effective January 1, 2014, the impact of the Qualifying Infrastructure Plant rider at PGL, and other impacts of rate design, had an approximate $32 million positive impact on margins.

The rate increase at MGU, effective January 1, 2014, resulted in an approximate $4 million positive impact on margins.

The interim rate increase at MERC, effective January 1, 2014, had an approximate $4 million positive impact on margins.

These increases were partially offset by the approximate $5 million negative impact of WPS's rate order, effective January 1, 2014. Although the PSCW approved a net rate increase, it was driven by the recovery of the 2012 decoupling under-collections to be recovered from customers in 2014, which has no impact on margins. See Note 25, Regulatory Environment, for more information.

- An approximate $23 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 higher weather-normalized volumes, partially offset by the impact of our decoupling mechanisms, increased margins approximately $40 million. In 2014, margins at the natural gas utilities were positively impacted by colder than normal weather, net of decoupling impacts at MERC, NSG, and PGL. Effective January 1, 2014, MGU and WPS no longer have decoupling mechanisms in place. During 2014, MERC reached its maximum accrued refund to customers under the annual 10% cap provision of its decoupling mechanism. In 2013, decoupling mechanisms were in place for all the natural gas utilities. Margins for certain customer classes in both years were sensitive to volume variances as they were not covered by the decoupling mechanisms. See Note 25, Regulatory Environment, for more information on our decoupling mechanisms.

Margins were negatively impacted year-over-year by approximately $17 million due to a reversal in 2013 of reserves established in 2012 against PGL and NSG regulatory assets related to decoupling. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanisms. See Note 25, Regulatory Environment, for more information.

Operating Income

Operating income at the natural gas utility segment decreased $33.1 million. This decrease was driven by a $130.3 million increase in operating expenses, partially offset by the $97.2 million increase in margins discussed above.

The increase in operating expenses was primarily due to:

- A $45.9 million increase in natural gas distribution costs, primarily at PGL. The increase in costs at PGL was driven by higher repairs and maintenance expense primarily due to higher costs to meet new compliance requirements.
- A $19.8 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 the majority of the increase in expenses, margins increased by an equal amount, resulting in no impact on earnings.

- A $15.5 million increase in bad debt expense, driven by higher natural gas costs in 2014, an increase in sales volumes, and rate increases. The majority of the increase in bad debt expense related to PGL and NSG and had no impact on earnings since it was offset by higher rates through a rider mechanism, resulting in higher margins.

- A $13.0 million increase in depreciation and amortization expense. This increase was driven by continued investment in property and equipment, primarily the AMRP at PGL. The increase was also driven by a $3.4 million reduction in expense in 2013 at MERC related to a new depreciation study approved by the MPUC on July 29, 2013, retroactive to January 1, 2012. In addition, MGU recorded a $2.5 million reduction in expense in 2013. 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 25, Regulatory Environment, for more information.

- An $8.7 million increase driven by higher information technology costs. New servers and software for natural gas management and work asset management systems were placed in service during the third quarter of 2013, resulting in higher asset usage charges from IBS. Also, in 2014, several information technology projects and upgrades were performed, and additional information technology services were provided by IBS.

- A $5.0 million increase in workers compensation and injuries and damages expense. This increase was driven by both more severe injuries and increased incidents in 2014, primarily at PGL.

- A $4.6 million net increase in energy efficiency program expenses at our natural gas utilities. This net increase in expenses was more than offset by an approximate $6 million related increase in margins.

- A $4.0 million increase in the cost of outside services employed, primarily driven by higher consulting and contract labor costs as a result of the AMRP at PGL.

- A $3.7 million increase in unrecoverable energy efficiency program expense at MERC. In the second quarter of 2014, MERC wrote off a regulatory asset recorded for conservation improvement program costs.

- A $3.0 million increase in customer accounts expense, driven in part by higher outsourced call center costs at PGL. The increase in call center costs was primarily due to additional services provided as a result of a project to standardize the customer billing system.

- A $2.7 million increase in taxes other than income taxes, driven in part by the Illinois invested capital tax. This tax is based on an entity's equity and long-term debt balances, which have increased for PGL. Higher property taxes also contributed to the increase in expense.

- A $0.1 million net increase in employee benefit costs, driven by:

An $8.5 million increase in stock-based compensation expense, primarily due to the year-over-year increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in our stock price.

A $4.3 million increase related to the negative year-over-year impact of the deferral of employee benefit costs in 2013 and the related amortization in 2014. In 2013, WPS deferred certain increases in pension and other employee benefit costs as a result of its 2013 rate order with the PSCW. WPS began amortizing this regulatory asset in 2014.

These increases were partially offset by a $12.7 million decrease in other employee benefit costs, primarily driven by higher discount rates assumed in 2014. The remeasurement of certain postretirement benefit plans in the first quarter of 2014 also contributed to the decrease. See Note 18, Employee Benefit Plans, for more information on this remeasurement.

Other Expense

Other expense at the natural gas utilities increased $3.5 million. Interest expense on long-term debt increased, driven by higher average long-term debt outstanding in 2014.

2013 Compared with 2012

Margins

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 its 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 25, 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 25, 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 recovered approximately $27 million more from 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 17, 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 25, 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 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.

- 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 25, 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, retroactive to January 2012. 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 25, 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 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.

Electric Utility Segment Operations

(Millions, except degree days)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Revenues	$1,286.4	$1,332.1	$1,297.4	(3.4)%	2.7%
Fuel and purchased power costs	471.6	536.9	562.1	(12.2)%	(4.5)%
Margins	814.8	795.2	735.3	2.5%	8.1%
Operating and maintenance expense	445.5	440.2	405.6	1.2%	8.5%
Depreciation and amortization expense	103.0	98.6	89.0	4.5%	10.8%
Taxes other than income taxes	45.8	49.1	47.6	(6.7)%	3.2%
Gain on sale of UPPCO, net of transaction costs	(85.4)	—	—	N/A	—%
Operating income	305.9	207.3	193.1	47.6%	7.4%
Miscellaneous income	11.1	9.8	2.6	13.3%	276.9%
Interest expense	47.4	36.4	35.9	30.2%	1.4%
Other expense	(36.3)	(26.6)	(33.3)	36.5%	(20.1)%
Income before taxes	$269.6	$180.7	$159.8	49.2%	13.1%
Sales in kilowatt-hours					
Residential	3,041.9	3,132.3	3,106.6	(2.9)%	0.8%
Commercial and industrial	8,258.8	8,504.0	8,574.5	(2.9)%	(0.8)%
Wholesale	3,053.9	4,327.2	4,614.7	(29.4)%	(6.2)%
Other	35.3	37.6	38.0	(6.1)%	(1.1)%
Total sales in kilowatt-hours	14,389.9	16,001.1	16,333.8	(10.1)%	(2.0)%

Weather

WPS:					
Actual heating degree days	8,564	8,051	6,356	6.4 %	26.7 %
Normal heating degree days	7,454	7,452	7,548	— %	(1.3)%
Actual cooling degree days	333	529	789	(37.1)%	(33.0)%
Normal cooling degree days	510	503	475	1.4 %	5.9 %
UPPCO (sold in August 2014):					
Actual heating degree days	6,639	9,496	7,749	(30.1)%	22.5 %
Normal heating degree days	8,675	8,665	8,757	0.1 %	(1.1)%
Actual cooling degree days	122	230	335	(47.0)%	(31.3)%
Normal cooling degree days	239	232	218	3.0 %	6.4 %

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.

2014 Compared with 2013

Margins

Electric utility segment margins increased $19.6 million, driven by:

- An approximate $41 million increase in margins related to WPS and UPPCO rate orders, effective January 1, 2014. Although the PSCW approved an electric rate decrease for WPS, the rate decrease was driven by 2013 fuel cost over-collections and 2012 decoupling over-collections that were being refunded to customers in 2014 and had no impact on margins. See Note 25, Regulatory Environment, for more information.

    Margins at WPS increased approximately $41 million as a result of the PSCW rate order, primarily driven by an increase in electric rate base from owning and operating the Fox Energy Center, which was included in rates beginning in 2014. In 2013, customer rates only included recovery of estimated purchased power costs from the Fox Energy Center.

UPPCO's retail electric rate increase resulted in an approximate $6 million increase in margins.

Margins at WPS were positively impacted by approximately $5 million mainly due to lower fly ash disposal costs in 2014. These costs are not included in the fuel rule recovery mechanism.

Margins decreased approximately $11 million related to fuel and purchased power cost under-collections at WPS in 2014, compared with over-collections in 2013. Under the fuel rule, WPS can only defer under or over-collections of certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

- An approximate $11 million increase in wholesale margins driven by higher prices. Wholesale prices increased due to higher generation costs as well as an increase in electric rate base, resulting from the purchase of the Fox Energy Center in 2013 and the installation of environmental projects at the Columbia plant in 2014. Wholesale customers proportionally shared in these price increases through formula rates.

- A partially offsetting decrease in margins of approximately $31 million related to sales volume variances. The decrease was primarily driven by the sale of UPPCO at the end of August 2014, which lowered margins related to sales volume variances by approximately $27 million. See Note 4, Dispositions, for more information. Margins from WPS's large commercial and industrial customers as well as residential customers also decreased, driven by lower use per customer in 2014. These decreases were partially offset by the impact of the termination of our decoupling mechanisms, effective January 1, 2014. See Note 25, Regulatory Environment, for more information. Our decoupling mechanisms did not cover large commercial and industrial customers.

Operating Income

Operating income at the electric utility segment increased $98.6 million. The increase was primarily driven by an $85.4 million net gain on the sale of UPPCO. See Note 4, Dispositions, for more information. The remaining increase in operating income was due to the $19.6 million increase in margins discussed above, partially offset by a $6.4 million increase in operating expenses.

The increase in operating expenses was driven by:

- A $13.6 million increase in maintenance expense, primarily due to planned major outages in 2014 at the Pulliam plant, Fox Energy Center, and Weston 4, as well as maintenance at certain other WPS generation plants. These increases were partially offset by the year-over-year impact of maintenance expenses associated with the Weston 3 planned major outage in 2013.

- A $6.0 million increase in costs at WPS associated with the acquisition and operation of the Fox Energy Center. The majority of this increase relates to the amortization of a regulatory asset related to the fee paid for the early termination of the Fox Energy Center power purchase agreement. Recovery of the amortization was included in the new rates.

- A $4.4 million increase in depreciation and amortization expense, mainly due to the acquisition of the Fox Energy Center at the end of the first quarter of 2013. In addition, we completed the installation of scrubbers at the Columbia plant in April 2014. This increase is partially offset by lower depreciation driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $3.8 million increase in electric transmission expense, which is net of lower transmission costs driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $2.8 million increase in amortization of previously deferred production tax credits related to the WPS Crane Creek wind project.

These increases were partially offset by:

- An $8.8 million net decrease in employee benefit costs, including the impact of the prior year deferral of some of these costs. Employee benefit costs other than stock-based compensation (discussed below) decreased $27.5 million in 2014. This decrease was partially driven by the continued funding of our pension plan and higher discount rates assumed in 2014 for both our pension and postretirement plans. The remeasurement of certain other postretirement benefit plans also contributed to the overall decrease in employee benefit costs. See Note 18, Employee Benefit Plans, for more information. This decrease was partially offset by:

Higher stock-based compensation expense of $4.2 million, which was primarily driven by an increase in the fair value of awards accounted for as liabilities. The increase in fair value resulted from an increase in our stock price.

The year-over-year impact of a deferral of certain increases in WPS employee benefit costs in 2013, recorded in accordance with its PSCW rate order, and the related amortization in 2014. Together, these changes increased employee benefit costs by $14.5 million at WPS.

- A $6.6 million decrease due to the year-over-year impact of WPS's 2013 deferral of the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center. The WPS 2013 PSCW rate order did not reflect this purchase or the related termination of a power purchase agreement. However, WPS did receive PSCW approval to defer ownership costs above or below its power purchase agreement expenses in 2013.

- A $3.3 million decrease in taxes other than income taxes, partially driven by the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $2.9 million decrease in customer-related expenses. This was driven by the year-over-year change in the amortization of amounts recoverable from or refundable to customers related to energy efficiency, as well as the sale of UPPCO in August 2014. See Note 4, Dispositions, for more information.

- A $1.3 million deferral of coal shipping costs related to minimum requirements under WPS's contracts for rail obligations. WPS received approval from the PSCW in the 2014 rate order to defer these costs. This deferral was offset by a decrease in margins.

Other Expense

Other expense increased $9.7 million. The primary driver was a $13.0 million increase in interest expense on long-term debt, driven by higher average outstanding long-term debt at WPS in 2014. An increase in AFUDC of $1.8 million at WPS partially offset this increase. AFUDC was higher largely due to the construction of the ReACT™ emission control technology at the Weston 3 plant and the System Modernization and Reliability Project, partially offset by environmental compliance projects at the Columbia plant completed earlier in 2014.

2013 Compared with 2012

Margins

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 25, Regulatory Environment, for more information on the 2013 PSCW rate order.

- 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 25, 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 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.

Electric Transmission Investment Segment Operations

	Year Ended December 31			Change in 2014	Change in 2013
(Millions)	2014	2013	2012	Over 2013	Over 2012
Earnings from equity method investments	$85.7	$89.1	$85.3	(3.8)%	4.5%

2014 Compared with 2013

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment decreased $3.4 million. The decrease resulted from lower earnings related to our approximate 34% ownership interest in ATC. In 2014, ATC recorded a reserve for an anticipated refund to customers related to a complaint filed with FERC requesting a lower return on equity for certain transmission owners. The reserve reduced our earnings from ATC by $6.6 million.

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.

Holding Company and Other Segment Operations

(Millions)	Year Ended December 31 2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Operating loss	$(17.7)	$(19.7)	$(15.7)	(10.2)%	25.5%
Other expense	(32.4)	(27.5)	(28.0)	17.8%	(1.8)%
Loss before taxes	$(50.1)	$(47.2)	$(43.7)	6.1%	8.0%

2014 Compared with 2013

Operating Loss

Operating loss at the holding company and other segment decreased $2.0 million. The improvement was driven by a $5.0 million gain on the abandonment of PDI's Winnebago Energy Center, as well as a $4.6 million decrease in operating losses at ITF. Also contributing to the decrease was a $2.7 million increase in operating income at IBS driven by an increase in its return on capital charged to the utilities. Partially offsetting these decreases were $10.4 million of transaction costs recorded in 2014 related to the proposed merger with Wisconsin Energy Corporation.

Other Expense

Other expense at the holding company and other segment increased $4.9 million. The increase was primarily due to an $11.0 million increase in interest expense on long-term debt, driven by the issuance of $400.0 million of Junior Subordinated Notes in August 2013. This increase was partially offset by a $3.5 million gain on the sale of land at the holding company, as well as a $2.0 million unrealized gain recorded on exchange-traded funds in 2014. In July 2014, exchange-traded funds previously held by IBS were transferred to the rabbi trust at the holding company. See Note 18, Employee Benefit Plans, for more information. Prior to July 2014, the unrealized gains (losses) on these investments were allocated to the other operating segments.

2013 Compared with 2012

Operating Loss

Operating loss at the holding company and other segment increased $4.0 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 $0.5 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.

Provision for Income Taxes

	Year Ended December 31 2014	2013	2012
Effective Tax Rate	41.0%	37.1%	33.0%

2014 Compared with 2013

Our effective tax rate increased in 2014. This increase was primarily due to a $13.0 million expense caused by the remeasurement of deferred taxes related to the sale of IES's retail energy business.

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 25, Regulatory Environment, for more information.

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.

For information on changes in the deferred income tax balances, see Note 16, Income Taxes.

Discontinued Operations

	Year Ended December 31			Change in	Change in
(Millions)	2014	2013	2012	2014 Over 2013	2013 Over 2012
Discontinued operations, net of tax	$1.8	$87.3	$45.4	(97.9)%	92.3%

2014 Compared with 2013

Earnings from discontinued operations, net of tax, decreased $85.5 million in 2014. These lower earnings were primarily driven by a decrease of $82.1 million related to the operations of IES's retail energy business, which was sold in November 2014. Included in this amount was a $46.6 million after-tax decrease in net unrealized gains on derivative contracts. In addition, we realized a $17.3 million after-tax loss on the sale in November 2014. See Note 4, Dispositions, for more information.

2013 Compared with 2012

Earnings from discontinued operations, net of tax, increased $41.9 million in 2013. These higher earnings were primarily driven by an increase of $27.4 million related to the operations of IES's retail energy business, which was sold in November 2014. See Note 4, Dispositions, for more information. In 2013 and 2012, we also remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. Discontinued operations increased $4.1 million as a result of these remeasurements. Finally, in 2012, we recognized after-tax losses from discontinued operations of $6.9 million related to WPS Westwood Generation, LLC (Westwood) and $4.0 million related to WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse). We 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, Dispositions, for more information.

LIQUIDITY AND CAPITAL RESOURCES

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

Operating Cash Flows

2014 Compared with 2013

During 2014, net cash provided by operating activities was $601.4 million, compared with $554.9 million during 2013. The $46.5 million increase in net cash provided by operating activities was driven by:

- A $1,538.6 million increase in cash collections from customers, mainly due to rate increases at the utilities, higher commodity prices, an increase in electric wholesale revenues, and colder weather in 2014. Included in the electric utility rate increase was the impact of the increase in rate base related to owning and operating the Fox Energy Center.

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

- A $27.0 million increase in cash from customer prepayments and credit balances. In 2013, cash received in relation to amounts billed was lower because customer prepayments had grown during an unusually warm 2012.

These increases in cash were partially offset by:

- A $1,274.2 million decrease in cash due to higher costs of natural gas, fuel, and purchased power in 2014. Additional cash was used in 2014 due to higher energy prices and the colder weather.

- A $159.7 million decrease in cash due to increased operating and maintenance costs in 2014. The increase in operating and maintenance costs was driven by higher natural gas distribution costs at PGL related to compliance activities, higher electric utility maintenance from planned major outages at WPS, and other higher WPS costs associated with owning and operating the Fox Energy Center beginning in March 2013.

- A $48.8 million decrease in cash driven by lower collateral requirements at IES in 2014. We sold IES's retail energy business in November 2014.

- A $31.8 million increase in contributions to pension and other postretirement benefit plans.

- A $30.7 million increase in cash paid for interest, primarily driven by higher average outstanding long-term debt in 2014.

- An $11.1 million decrease in cash received for income taxes, partially driven by cash paid for income taxes related to the gain on the sale of UPPCO in August 2014. This decrease in cash was partially offset by a federal income tax refund received in the first quarter of 2014 for an amended return.

- A $9.0 million decrease in cash from various deferrals at WPS, primarily for system support resource costs, precertification costs for a potential new natural gas combined cycle generating unit, and the net difference between actual and rate case-approved costs resulting from the purchase of the Fox Energy Center.

- A $5.4 million increase in cash used for environmental remediation activities.

2013 Compared with 2012

During 2013, net cash provided by operating activities was $554.9 million, compared with $573.8 million million during 2012. The $18.9 million decrease in net cash provided by operating activities was largely 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.

- 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 tax 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 IES. Collateral requirements are based on forward positions with counterparties.

These decreases in cash were partially offset by:

- A $210.9 million decrease in contributions to pension and other postretirement benefit plans.

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

Investing Cash Flows

2014 Compared with 2013

During 2014, net cash used for investing activities was $336.5 million, compared with $1,022.7 million during 2013. The $686.2 million decrease in net cash used for investing activities was primarily due to:

- The positive year-over-year impact of cash used to purchase two businesses in 2013. WPS purchased Fox Energy Company LLC for $391.6 million, and IES purchased Compass Energy Services for $15.7 million in 2013. See Note 3, Acquisitions, for more information on the Fox Energy Company LLC acquisition.

- The receipt of proceeds of $336.5 million in 2014 related to the sale of UPPCO. See Note 4, Dispositions, for more information.

- The receipt of proceeds of $311.6 million in 2014 related to the sale of IES. See Note 4, Dispositions, for more information.

These decreases in cash used were partially offset by:

- A $195.8 million increase in cash used for capital expenditures other than the Fox Energy Center acquisition discussed above.

- A $115.5 million increase in cash used due to the required funding of the rabbi trust for deferred compensation and certain nonqualified pension plans. The proposed merger with Wisconsin Energy Corporation qualified as a potential change in control event under the rabbi trust agreement, which required the funding of the rabbi trust. See Note 2, Proposed Merger with Wisconsin Energy Corporation, for more information about the merger.

- The year-over-year negative impact of the receipt of a $69.0 million Section 1603 Grant for the Crane Creek wind project in 2013.

2013 Compared with 2012

During 2013, net cash used for investing activities was $1,022.7 million, compared with $602.6 million during 2012. The $420.1 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. IES 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 $74.8 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.

Capital Expenditures

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

Reportable Segment (millions)	2014	2013	2012	Change in 2014 Over 2013	Change in 2013 Over 2012
Natural gas utility	$456.5	$370.0	$375.1	$86.5	$(5.1)
Electric utility	286.6	615.0	163.9	(328.4)	451.1
IES	0.9	2.6	2.0	(1.7)	0.6
Holding company and other	121.0	73.2	53.4	47.8	19.8
Integrys Energy Group consolidated	$865.0	$1,060.8	$594.4	$(195.8)	