INTEGRYS ENERGY GROUP, INC.
Form 10-K
February 29, 2012
Table of Contents

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, 2011

OR

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

For the transition period from to

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-11337	**INTEGRYS ENERGY GROUP, INC.** (A Wisconsin Corporation) 130 East Randolph Street Chicago, IL 60601-6207 (312) 228-5400	39-1775292

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $1 par value	New York Stock Exchange

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 o

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 o 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 o

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 o

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. o

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 o
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

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

$4,039,305,304 as of June 30, 2011

Number of shares outstanding of each class of common stock, as of February 24, 2012

Common Stock, $1 par value, 78,287,906 shares

DOCUMENT INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Integrys Energy Group, Inc. Annual Meeting of Shareholders to be held on May 10, 2012 are incorporated by reference into Part III.

Table of Contents

INTEGRYS ENERGY GROUP, INC.

ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2011

TABLE OF CONTENTS

Table of Contents

Table of Contents

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
ICR	Infrastructure Cost Recovery
IRS	United States Internal Revenue Service
ITF	Integrys Transportation Fuels, LLC
LIFO	Last-in, First-out
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
MISO	Midwest Independent Transmission System Operator, Inc.
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utility Commission
N/A	Not Applicable
NSG	North Shore Gas Company
OCI	Other Comprehensive Income
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

Table of Contents

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, but rather are subject to numerous management assumptions, risks, and uncertainties. Therefore, actual results may differ materially from those expressed or implied by these statements. 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 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, 2011 and those identified below:

- The timing and resolution of rate cases and related negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated businesses;

- Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting coal-fired generation facilities and renewable energy standards;

- Other 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;

- Costs and effects of litigation and administrative proceedings, settlements, investigations, and claims, including manufactured gas plant site cleanup, third-party intervention in permitting and licensing projects, compliance with Clean Air Act requirements at generation plants, and prudence and reconciliation of costs recovered in revenues through automatic gas cost recovery mechanisms;

- 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 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 timing and outcome of any audits, disputes, and other proceedings related to taxes;

- The effects, extent, and timing of additional competition or regulation in the markets in which our subsidiaries operate;

- The ability to retain market-based rate authority;

- The risk associated with the value of goodwill or other intangible assets and their possible impairment;

- The investment performance of employee benefit plan assets and related actuarial assumptions, which impact future funding requirements;

- The impact of unplanned facility outages;
- Changes in technology, particularly with respect to new, developing, or alternative sources of generation;
- The effects of political developments, as well as changes in economic conditions and the related impact on customer use, customer growth, and our ability to adequately forecast energy use for all of our customers;
- Potential business strategies, including mergers, acquisitions, and construction or disposition of assets or businesses, which cannot be assured to be completed timely or within budgets;
- 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 effectiveness of risk management strategies, the use of financial and derivative instruments, and the related recovery of these costs from customers in rates;
- 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;
- Unusual weather and other natural phenomena, including related economic, operational, and/or other ancillary effects of any such events;
- The ability to use tax credit and loss carryforwards;
- The financial performance of ATC and its corresponding contribution to our earnings;
- 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.

Table of Contents

PART I

ITEM 1. BUSINESS

A. GENERAL

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

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

Integrys Energy Group, Inc.

We are a diversified energy holding company with regulated natural gas and electric utility operations, nonregulated energy operations, and an approximate 34% equity ownership interest in ATC, a regulated electric transmission company. We were incorporated in Wisconsin in 1993.

Natural Gas Utility Segment

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

Electric Utility Segment

The electric utility segment includes the regulated electric utility operations of WPS and UPPCO. UPPCO, a Michigan corporation, began operations in 1884. We acquired UPPCO in September 1998.

Integrys Energy Services

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

Electric Transmission Investment

The electric transmission investment segment consists of our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Wisconsin, Michigan, Minnesota, and Illinois. ATC began operations in 2001. See Note 9, *Investments in Affiliates, at Equity Method*, for more information about ATC.

Holding Company and Other Segment

The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at WPS, MGU, MERC, UPPCO, PGL, NSG, and IBS. The compressed natural gas operations of ITF are included in this segment as of September 1, 2011, the date on which we acquired Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle). See Note 4, *Acquisition*, for more information about the acquisition of Trillium and Pinnacle.

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.

Table of Contents

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 statements, and other information (including exhibits) filed or furnished electronically with the SEC, at the SEC s website at www.sec.gov.

B. REGULATED NATURAL GAS UTILITY OPERATIONS

Our regulated natural gas utilities provide service to approximately 1,682,000 residential, commercial and industrial, transportation, and other customers. Our customers are located in Chicago and the northern suburbs of Chicago, northeastern Wisconsin and an adjacent portion of Michigan s Upper Peninsula, various cities and communities throughout Minnesota, and the southern portion of lower Michigan.

Facilities

For information regarding our regulated natural gas facilities, see Item 2, *Properties*. For our utility plant asset book value, see Note 6, *Property, Plant, and Equipment*.

Natural Gas Supply

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

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

For more information on our regulated natural gas utility supply and transportation contracts, see Note 16, *Commitments and Contingencies*.

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

PGL owns and operates an underground natural gas storage reservoir in central Illinois (Manlove Field) and a natural gas pipeline system that connects Manlove Field to Chicago with eight major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in PGL s regulatory rate base. PGL also uses a portion of these 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 through an injection, and PGL later returns the natural gas to the customers when needed through a withdrawal. Title to the natural gas does not transfer to PGL; therefore, all natural gas related only to the hub remains customer-owned. PGL recognizes service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

Set forth below is a rollforward of 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)	**2011**	**2010**	**2009**
Beginning Balance, January 1	**5,156**	**5,187**	4,541
Injections	**7,000**	**7,010**	6,978
Withdrawals	**(6,895)**	**(7,041)**	(6,332)
Ending Balance, December 31	**5,261**	**5,156**	5,187

(Millions)	**2011**	**2010**	**2009**
Natural gas hub service fees	**$ 5.4**	**$ 10.3**	$ 5.8

Table of Contents

Our regulated natural gas utilities had adequate capacity to meet all firm natural gas demand obligations during 2011 and expect to have adequate capacity to meet all firm obligations during 2012. Our regulated natural gas utilities forecast design peak-day throughput is 3,736 MDth for the 2011 through 2012 heating season.

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

(MDth)	2011	2010	2009
Natural gas purchases	**217,288**	204,794	224,762
Natural gas purchases for electric generation	**1,780**	1,389	957
Customer-owned natural gas received	**181,021**	172,180	164,676
Underground storage, net	**(1,425)**	3,494	1,080
Hub fuel in kind *	**180**	176	141
Liquefied petroleum gas (propane)	**1**	4	12
Owned storage cushion injection	**(1,098)**	(1,094)	(1,272)
Contracted pipeline and storage compressor fuel, franchise requirements, and unaccounted- for natural gas	**(10,809)**	(7,544)	(9,692)
Total	**386,938**	373,399	380,664

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

Regulatory Matters

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

Sales are made and services are rendered by the regulated natural gas utilities pursuant to rate schedules on file with the respective commissions. These rate schedules contain various service classifications, which largely reflect customers different uses and levels of consumption. Our regulated natural gas utilities bill customers for the distribution of natural gas as well as for a natural gas charge representing third-party costs for purchasing, transporting, and storing natural gas. This charge also includes gains, losses, and costs incurred under hedging programs, the amount of which is also subject to applicable commission authority. Prudently incurred natural gas costs are passed directly through to customers in rates 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 regulated natural gas utilities distribute is transported to our distribution systems by interstate pipelines. The pipelines transportation and storage services, including PGL s natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. Under United States Department of Transportation regulations, the state commissions are responsible for monitoring our regulated natural gas utilities safety compliance programs for our pipelines under 49 Code of Federal Regulations (CFR) Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

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

See Note 26, *Regulatory Environment*, for information regarding rate cases, decoupling mechanisms, and bad debt recovery mechanisms in place at the regulated natural gas utilities.

Other Matters

Seasonality

The natural gas throughput of our regulated natural gas utilities is generally higher during the winter months because the heating requirements of customers are temperature driven. During 2011, the regulated natural gas utility segment recorded approximately 64% of its revenues in January, February, March, November, and December.

Table of Contents

Competition

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

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

Working Capital Requirements

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

C. REGULATED ELECTRIC UTILITY OPERATIONS

Our regulated electric utility operations of WPS and UPPCO provide service to approximately 493,000 residential, commercial and industrial, wholesale, and other customers. WPS s customers are located in northeastern Wisconsin and an adjacent portion of Michigan s Upper Peninsula. UPPCO s customers are located in Michigan s Upper Peninsula. Wholesale electric service is provided to various customers, including municipal utilities, electric cooperatives, energy marketers, other investor-owned utilities, and municipal joint action agencies. Beginning in 2012, UPPCO no longer provides service to any wholesale electric customers due to the expiration of its remaining wholesale electric contracts in 2011. In 2011, retail electric revenues accounted for 82.9% of total electric revenues, while wholesale electric revenues accounted for 17.1% of total electric revenues.

In 2011, WPS reached a firm net design peak of 2,344 megawatts (MW) on July 20. At the time of this summer peak, WPS s total firm resources (i.e., generation plus firm purchases) totaled 3,164 MW. The summer period is the most relevant for WPS s regulated electric utility capacity due to the air conditioning requirements of its customers. 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 17.4% reserve margin requirement from January 1 through May 31, 2012, and 14.4% for the remainder of 2012. The MPSC does not have minimum guidelines for future supply reserves.

In 2011, UPPCO reached a firm net design peak of 121 MW on February 18. At the time of this peak, UPPCO s total firm resources totaled 148 MW. The MPSC does not have minimum guidelines for future supply reserves; however, the MISO short-term planning reserve margin requirements described above also apply to UPPCO.

WPS and UPPCO expect future supply reserves to meet the minimum planning reserve margin requirements for 2012. WPS and UPPCO had adequate capacity through company-owned generation units and power purchase contracts to meet all firm electric demand obligations during 2011 and expect to have adequate capacity to meet all obligations during 2012.

Facilities

For a complete list of our electric utility facilities, see Item 2, *Properties*. For our utility plant asset book value, see Note 6, *Property, Plant, and Equipment*.

Table of Contents

Electric Supply

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

Electric Generation and Supply Mix

The sources of our electric utility supply were as follows:

(Millions) **Energy Source (kilowatt-hours)**	**2011**	**2010**	**2009**
Company-owned generation units			
Coal	**8,634.5**	10,232.9	8,974.3
Hydroelectric	**348.9**	306.5	225.9
Wind	**309.3**	287.7	46.4
Natural gas, fuel oil, and tire derived	**135.8**	105.4	71.4
Total company-owned generation units	**9,428.5**	10,932.5	9,318.0
Power purchase contracts			
Nuclear (Kewaunee Power Station)	**2,674.4**	2,940.8	2,663.9
Natural gas (Fox Energy Center, LLC and Combined Locks Energy Center, LLC)	**1,593.9**	608.4	673.7
Hydroelectric	**570.7**	526.7	569.5
Wind	**210.6**	149.1	136.9
Other	**235.8**	205.5	571.1
Total power purchase contracts	**5,285.4**	4,430.5	4,615.1
Purchased power from MISO	**1,605.2**	781.9	1,898.9
Purchased power from other	**100.1**	342.9	54.4
Total purchased power	**6,990.7**	5,555.3	6,568.4
Opportunity sales			
Sales to MISO	**(1,242.0)**	(734.5)	(462.5)
Net sales to other	**(64.6)**	(248.4)	(450.5)
Total opportunity sales	**(1,306.6)**	(982.9)	(913.0)
Total electric utility supply	**15,112.6**	15,504.9	14,973.4

Fuel Costs

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

Fuel Type	2011	2010	2009
Coal	**$ 2.44**	$ 2.05	$ 1.94
Natural gas	**5.64**	6.28	6.73
Fuel oil	**21.24**	18.44	17.09

Coal Supply

Coal is the primary fuel source for WPS s electric generation facilities. WPS s regulated fuel portfolio strategy is to maintain a 35- to 45-day supply of coal at each plant site. Currently the coal supply is higher than the portfolio strategy due to lower coal burning rates as a result of decreased natural gas prices and economic conditions. The majority of the coal is purchased from Powder River Basin mines located in Wyoming. This low sulfur coal has been WPS s lowest cost coal source of any of the subbituminous coal-producing regions in the United States. Historically, WPS has purchased coal directly from the producer for its wholly owned plants. WPS also purchases the coal for the jointly owned Weston 4 plant and Dairyland Power Cooperative reimburses WPS for their share of the coal costs. Wisconsin Power and Light purchases coal for the jointly owned Edgewater and Columbia plants and is reimbursed by WPS for its share of the coal costs. At December 31, 2011, WPS had coal transportation contracts in place for 100% of its 2012 coal transportation requirements. For more information on coal purchases and coal deliveries under contract, see Note 16, *Commitments and Contingencies*.

Table of Contents

Power Purchase Agreements

Our electric utilities enter into short-term and long-term power purchase agreements to meet a portion of their electric energy supply needs. For more information on power purchase obligations, see Note 16, *Commitments and Contingencies*.

Regulatory Matters

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

The PSCW sets rates through its ratemaking process, which is based on recovery of operating costs and a return on invested capital. One of the cost recovery components is fuel and purchased power, which is governed by a fuel window mechanism, as described in Note 1(f), *Summary of Significant Accounting Policies Revenues and Customer Receivables*. The MPSC and the FERC ratemaking processes are similar to those of the PSCW, with the exception of fuel and purchased power, which are recovered on a one-for-one basis.

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

Hydroelectric Licenses

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

Other Matters

Seasonality

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

Competition

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

Michigan electric energy markets are open to competition. However, an active competitive market has not yet developed in the Upper Peninsula of Michigan, primarily due to a lack of excess generation and transmission system capacity.

D. INTEGRYS ENERGY SERVICES

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

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

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

Recent Developments

Throughout 2009 and 2010, Integrys Energy Services was repositioned to focus on serving retail natural gas and retail electric customers concentrated in the northeast quadrant of the United States, and investing in energy assets with renewable attributes. See Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Introduction*, for a discussion of the current strategy for Integrys Energy Services.

In October 2010, Integrys Energy Services announced the launch of a joint venture with Duke Energy Generation Services to build and finance distributed solar projects throughout the United States. Duke Energy Generation Services and Integrys Energy Services will equally fund the necessary equity capital for construction and ownership of the solar projects, and are considering pursuing financing to be secured by the joint venture. See Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Future Capital Requirements and Resources*, for estimated construction expenditures for Integrys Energy Services.

Energy Supply

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

Facilities

For information regarding the energy asset facilities owned by Integrys Energy Services, see Item 2, *Properties*. For our nonregulated plant asset book value, see Note 6, *Property, Plant, and Equipment*.

Fuel Supply for Generation Facilities

Integrys Energy Services fuel inventory policy varies for each generation facility depending on the type of fuel used. The natural gas-fired facilities (78.0% of its installed generation portfolio) are subject to market price volatility, and are dispatched to produce energy only when it is economical to do so. The Westwood facility (12.2% of its installed generation portfolio) burns waste coal left behind by mining operations and has several years supply on site. All fuel is located within a seven-mile radius of the facility. The renewable energy facilities (9.8% of its installed generation portfolio) are all powered by renewable resources such as solar irradiance or landfill gas. There is no market price risk associated with the fuel supply of these facilities; however, production at these facilities can be intermittent due to the availability of the renewable energy resource.

Regulatory Matters

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

Other Matters

Customer Segmentation

As of December 31, 2011, Integrys Energy Services largest retail electric markets included the Illinois, New York, New England, Mid-Atlantic, and Michigan regions. Integrys Energy Services largest retail natural gas markets included Wisconsin, Illinois, Ohio, and Michigan. Integrys Energy Services continuously reviews and evaluates the profitability of its operations in each of its markets. Integrys Energy Services continues to concentrate on adding customers in existing markets and placing emphasis on business that provides the appropriate rate of return, and currently has no plans to expand into new geographic regions. See Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Introduction,* for a discussion of the current strategy for Integrys Energy Services.

Integrys Energy Services is not dependent on any one customer segment. Rather, a significant percentage of its retail sales volume is derived from several industries, including paper and allied products, general government and national security, food and kindred products, schools (including primary, secondary, colleges, and universities), chemicals and paint, and steel and foundries.

Table of Contents

Seasonality

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

Competition

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

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

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

Working Capital

The working capital needs of Integrys Energy Services vary significantly over time due to volatility in commodity prices and related margin calls, and levels of natural gas storage inventories. Integrys Energy Services working capital needs are met by cash generated from operations, equity infusions, and debt (both long-term and short-term). As of December 31, 2011, Integrys Energy Services had the ability to borrow up to $765.0 million through an intercompany credit facility with us. As of December 31, 2011, we have provided total parental guarantees of $532.0 million on behalf of Integrys Energy Services, which includes guarantees for the current retail business as well as residual guarantees related to assets sold in 2009 and 2010.

E. ENVIRONMENTAL MATTERS

For information on our environmental matters, see Note 16, *Commitments and Contingencies*.

F. 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*.

Table of Contents

G. EMPLOYEES

At December 31, 2011, our consolidated subsidiaries had the following employees:

	Total Number of Employees	Percentage of Employees Covered by Collective Bargaining Agreements
WPS	**1,304**	**69%**
IBS	**1,252**	
PGL	**1,077**	**79%**
Integrys Energy Services	**276**	
MERC	**217**	**20%**
NSG	**163**	**80%**
MGU	**157**	**69%**
UPPCO	**115**	**82%**
ITF	**58**	
Total	**4,619**	**46%**

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

Union	Subsidiary	Contract Expiration Date
Local 310 of the International Union of Operating Engineers	WPS	October 13, 2012
Local 18007 of the Utility Workers Union of America	PGL	April 30, 2013
Local 31 of the International Brotherhood of Electrical Workers, AFL CIO	MERC	May 31, 2013
Local 2285 of the International Brotherhood of Electrical Workers	NSG	June 30, 2013
Local 510 of the International Brotherhood of Electrical Workers, AFL CIO	UPPCO	April 12, 2014
Local 12295 of the United Steelworkers of America, AFL CIO CLC	MGU	January 15, 2015
Local 417 of the Utility Workers Union of America, AFL CIO	MGU	February 15, 2016

Table of Contents

H. EXECUTIVE OFFICERS OF INTEGRYS ENERGY GROUP

Name and Age (1)		Position and Business Experience During Past Five Years	Effective Date
Charles A. Schrock	58	Chairman, President and Chief Executive Officer	04-01-10
		President and Chief Executive Officer	01-01-09
		President and Chief Executive Officer of WPS	05-31-08
		President of WPS	02-21-07
		President and Chief Operating Officer Generation WPS	08-15-04
Lawrence T. Borgard	50	President and Chief Operating Officer Utilities	04-05-09
		President and Chief Operating Officer Integrys Gas Group (2)	02-21-07
		President and Chief Operating Officer Energy Delivery WPS	08-15-04
Phillip M. Mikulsky	63	Executive Vice President Business Performance and Shared Services	12-26-10
		Executive Vice President Corporate Development and Shared Services	09-21-08
		Executive Vice President and Chief Development Officer	02-21-07
		Executive Vice President Development	09-12-04
Mark A. Radtke	50	Executive Vice President and Chief Strategy Officer	12-26-10
		Chief Executive Officer Integrys Energy Services	01-10-10
		President and Chief Executive Officer Integrys Energy Services	06-01-08
		President Integrys Energy Services (previously named WPS Energy Services, Inc.)	10-17-99
Joseph P. O Leary	57	Senior Vice President and Chief Financial Officer	06-04-01
Diane L. Ford	58	Vice President and Corporate Controller	02-21-07
		Vice President Controller and Chief Accounting Officer	07-11-99
William J. Guc	42	Vice President and Treasurer	12-01-10
		Vice President Finance and Accounting and Controller Integrys Energy Services	03-07-10
		Vice President and Controller Integrys Energy Services	09-21-08
		Controller Integrys Energy Services (previously named WPS Energy Services)	02-21-05
William D. Laakso	49	Vice President Human Resources	09-21-08
		Interim Vice President Human Resources IBS	05-15-08
		Director Workforce and Organizational Development WPS	08-12-07
		Director of Organizational Development WPS	12-12-05
James F. Schott	54	Vice President External Affairs	03-22-10
		Vice President Regulatory Affairs	07-18-04
Barth J. Wolf	54	Vice President, Chief Legal Officer and Secretary	07-31-07
		Vice President Legal Services and Chief Compliance Officer IBS	02-21-07
		Secretary and Manager Legal Services	09-19-99
Daniel J. Verbanac	48	President Integrys Energy Services	01-01-10
		Chief Operating Officer Integrys Energy Services (previously named WPS Energy Services)	02-15-04

(1) Officers and their ages are as of December 31, 2011. None of the executives listed above are related by blood, marriage, or adoption to any of our other officers listed or to any of our directors. Each officer holds office until his or her successor has been duly elected and qualified, or until his or her death, resignation, disqualification, or removal.

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

Table of Contents

ITEM 1A. RISK FACTORS

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

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

We are subject to comprehensive regulation by several federal and state regulatory agencies and local governmental bodies. This regulation significantly influences our operating environment and may affect our ability to recover costs from customers of our regulated operations. 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 results of operations.

The rates, including adjustments determined under riders, which our regulated utilities are allowed to charge for their 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 the regulated utilities to have been prudently incurred. In addition, the regulatory process will not always result in rates that will produce full recovery of such costs or provide for a reasonable return on equity. Certain expense and revenue items are deferred as regulatory assets and liabilities for future recovery or refund to customers, as authorized by regulators. Future recovery of regulatory assets is not assured, and is generally subject to review by regulators in rate proceedings for prudence and reasonableness. If recovery of costs is not approved or is no longer deemed probable, regulatory assets would be recognized in current period expense and could have a material adverse impact on our financial results.

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

We are subject to numerous federal and state environmental laws and regulations that affect many aspects of our operations, including future operations. These laws and regulations relate to air emissions, water quality, wastewater discharges, and the generation, transport, and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections, and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, install pollution control equipment or environmental monitoring equipment at our facilities, incur fees for emissions and permits, and incur expenditures for cleanup costs, damages arising from contaminated properties, and monitoring obligations. In addition, there is uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Compliance with current and future environmental laws and regulations may result in increased capital, operating, and other costs, and non-compliance could result in fines, penalties, and injunctive measures affecting our facilities.

Existing environmental laws or regulations may also be revised and/or new laws or regulations seeking to protect the environment may be adopted or become applicable to us. These laws and regulations include, but are not limited to, regulation regarding mercury, sulfur dioxide, and nitrogen oxide emissions, and the management of coal combustion byproducts, including fly ash. 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. Costs associated with these potential actions could affect our results of operations and financial condition.

Our natural gas utility subsidiaries are accruing liabilities and deferring costs (recorded as regulatory assets) incurred in connection with their 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 also vary from the amounts currently accrued.

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.

Table of Contents

We may incur significant costs if laws or regulations are adopted to address climate change.

Political interest in climate change and the effects of greenhouse gas emissions, most notably carbon dioxide, are a concern for the energy industry. Although no legislation is currently pending that would affect us, state or federal legislation could be passed in the future to regulate greenhouse gas emissions. In addition, the EPA has adopted regulations under the Clean Air Act (CAA) that apply to permitting new or significantly modified facilities. The EPA also announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. Until legislation is passed at the federal or state level or the EPA adopts final rules for electric utility steam generating units, it remains unclear as to (1) which industry sectors will be impacted, (2) when compliance will be required, (3) the magnitude of the greenhouse gas emissions reductions that will be required, and (4) the costs and opportunities associated with compliance.

It is possible that future carbon regulation will increase the cost of electricity produced at coal-fired generation units. Future regulation may also affect the capital expenditures we would make at our generation units, including costs to further limit the greenhouse gas emissions from our operations through carbon capture and storage technology. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could also affect the availability or cost of fossil fuels. Future legislation designed to reduce greenhouse gas emissions could make some generating units uneconomical to maintain or operate and could impact future results of operations, cash flows, and financial condition if such costs are not recoverable through regulated rates.

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, a greenhouse gas. 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, which could have a material adverse impact on our results of operations and financial condition.

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

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

- Fluctuations in general economic conditions and growth in the service areas in which we operate;
- Weather conditions and seasonality;
- The amount of energy available from current or new competitors; and
- Our customers continued focus on energy efficiency.

Our operations are subject to risks arising from the reliability of our power plants and distribution system, as well as the reliability of third-party transmission providers.

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

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

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

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

Table of Contents

Our operations are subject to risks beyond our control, including but not limited to, cyber security attacks, terrorist attacks, acts of war, or loss of 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 with other third parties. A cyber security attack may occur despite our security measures or those that we require our vendors to take, including compliance with reliability standards and critical infrastructure protection standards. 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. The cost of repairing damage to our facilities or for legal claims caused by these attacks may not be recoverable in rates or may exceed the insurance limits on our insurance policies or, in some cases, may not be covered by insurance. The high cost or potential unavailability of insurance to cover terrorist activity may also adversely impact our results of operations and financial conditions.

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.

Counterparties and customers may not meet their obligations.

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

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

Any change in our ability to sell electricity generated from our facilities at market-based rates may impact earnings.

The FERC has authorized certain of our subsidiaries to sell generation from their facilities at market prices. The FERC retains the authority to modify or withdraw this market-based rate authority. If the FERC determines that the market is not workably competitive, that we or our subsidiaries possess market power, that we are not charging just and reasonable rates, or that we have not complied with the rules required in order to maintain market-based rates, the FERC may require our subsidiaries to sell power at a price based upon the costs incurred in producing the power. Our revenues and profit margins may be negatively affected by any reduction by the FERC of the rates we may receive.

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 is dependent 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.

Table of Contents

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

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

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

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits and net operating loss carryforwards available under the applicable tax codes. We have not fully used these tax credits and net operating loss carryforwards in our previous tax filings, and we may not be able to fully use the tax credits and net operating losses available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit the use of such credits and losses. In addition, any future disallowance of some or all of those tax credits or net operating loss carryforwards as a result of legislative change or adverse determination by one of the applicable taxing jurisdictions could materially affect our tax obligations and financial results.

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 remain in effect for any given period of time or that a credit rating 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.

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

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

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

Table of Contents

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 2. PROPERTIES

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2011:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)
Steam	Columbia Units 1 and 2	Portage, WI	Coal	349.6(2)
	Edgewater Unit 4	Sheboygan, WI	Coal	98.1(2)
	Pulliam (4 units)	Green Bay, WI	Coal	328.4
	Weston Units 1, 2, and 3	Marathon County, WI	Coal	458.9
	Weston Unit 4	Marathon County, WI	Coal	382.5(2)
Total Steam				1,617.5
Combustion Turbine and Diesel	De Pere Energy Center	De Pere, WI	Natural Gas	163.6
	Gladstone	Gladstone, MI	Oil	18.4
	Juneau #31	Adams County, WI	Distillate Fuel Oil	6.3(2)
	Pulliam #31	Green Bay, WI	Natural Gas	85.0
	West Marinette #31	Marinette, WI	Natural Gas	38.3
	West Marinette #32	Marinette, WI	Natural Gas	34.1
	West Marinette #33	Marinette, WI	Natural Gas	77.7
	Weston #31	Marathon County, WI	Natural Gas	17.4
	Weston #32	Marathon County, WI	Natural Gas	46.9
Total Combustion Turbine and Diesel				487.7
Hydroelectric	Various	Michigan	Hydro	19.4
	Various	Wisconsin	Hydro	67.6(3)
Total Hydroelectric				87.0
Wind	Lincoln	Wisconsin	Wind	1.1
	Crane Creek	Iowa	Wind	19.5
Total Wind				20.6
Total System				2,212.8

(1) Based on capacity ratings for July 2012, which can differ from nameplate capacity, especially on wind projects. The summer period is the most relevant for capacity planning purposes at our electric segment as 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, and WPS holds a 31.8% ownership interest in these facilities.

- WPS operates the Weston 4 facility and holds a 70% ownership in this facility, while Dairyland Power Cooperative holds the remaining 30% interest.

- WRPC owns and operates the Juneau unit. WPS holds a 50% ownership interest in WRPC.

(3) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50% ownership interest in WRPC; however, WPS is entitled to 66.7% of total capacity at Castle Rock and Petenwell. WPS s share of capacity for Castle Rock is 11.7 megawatts, and WPS s share of capacity for Petenwell is 13.9 megawatts.

As of December 31, 2011, our electric utilities owned approximately 25,000 miles of electric distribution lines located in Michigan and Wisconsin and approximately 180 distribution substations.

Table of Contents

Natural Gas Facilities

At December 31, 2011, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 22,000 miles of natural gas distribution mains,
- Approximately 1,020 miles of natural gas transmission mains,
- Approximately 290 natural gas distribution and transmission gate stations,
- Approximately 1.3 million natural gas lateral services,
- A 3.9 billion-cubic-foot underground natural gas storage field located in Michigan,
- A 38.2 billion-cubic-foot underground natural gas storage reservoir located in central Illinois,* and
- A 2 billion-cubic-foot liquefied natural gas plant located in central Illinois.*

---

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

General

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

B. INTEGRYS ENERGY SERVICES

The following table summarizes information on the energy asset facilities owned by Integrys Energy Services as of December 31, 2011:

Type	Name	Location	Fuel	Rated Capacity (Megawatts) (1)

Combined Cycle	Beaver Falls	Beaver Falls, NY	Gas/Oil	80.6
	Combined Locks	Combined Locks, WI	Gas	45.5(2)
	Syracuse	Syracuse, NY	Gas/Oil	82.8
Total Combined Cycle				208.9
Steam	Westwood	Tremont, PA	Waste Coal	32.5
Reciprocating Engine	Winnebago	Rockford, IL	Landfill Gas	6.1
Solar	Various	Various States	Solar Irradiance	20.2(3)
Total Energy Assets				267.7

				Length of Pipeline (Miles)
Landfill Gas Transportation	LGS	Brazoria County, TX	N/A	33 miles

(1) Based on summer rated capacity.

(2) Combined Locks has an additional five megawatts of capacity available at this facility through the lease of a steam turbine.

(3) The solar facilities consist of small distributed solar projects ranging from 0.1 to 2.3 megawatts in size. A portion of the solar facilities are wholly owned by subsidiaries of Integrys Energy Services and others are owned by INDU Solar Holdings, LLC, which is a jointly owned subsidiary of Integrys Energy Services and Duke Energy Generation Services. Of the capacity listed, 6.8 megawatts is Integrys Energy Services portion of total solar capacity based on their 50% ownership in INDU Solar Holdings, LLC.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS

For information on material legal proceedings and matters related to us and our subsidiaries, see Note 16, *Commitments and Contingencies*.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

Table of Contents

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:

	2011			2010		
Quarter	**High**	**Low**	**Dividends**	**High**	**Low**	**Dividends**
First	**$ 51.03**	**$ 47.51**	**$ 0.68**	$ 47.67	$ 40.53	$ 0.68
Second	**54.02**	**49.10**	**0.68**	50.92	42.81	0.68
Third	**52.79**	**42.76**	**0.68**	52.74	42.92	0.68
Fourth	**54.61**	**45.75**	**0.68**	54.45	46.73	0.68

As of the close of business on February 24, 2012, we had 29,465 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. For information regarding restrictions on the ability of subsidiaries to pay us dividends, see Item 7, *Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources* and Note 20, *Common Equity*.

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 year ended December 31, 2011:

			Issuer Purchases of Equity Securities	
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
01/01/11 - 01/31/11 (1)	9,788	$ 49.09		
02/01/11 - 02/28/11				
03/01/11 - 03/31/11				
04/01/11 - 04/30/11				
05/01/11 - 05/31/11 (1) (2)	126,838	53.61		
06/01/11 - 06/30/11 (1) (2) (3)	82,503	50.87		
07/01/11 - 07/31/11 (1) (2)	16,082	52.02		
08/01/11 - 08/31/11 (2)	20,799	47.62		
09/01/11 - 09/30/11 (2) (3)	76,823	50.60		
10/01/11 - 10/31/11 (1) (2)	23,009	50.16		
11/01/11 - 11/30/11 (1) (2)	21,666	51.36		
12/01/11 - 12/31/11 (1) (2) (3)	117,514	52.45		
Total	495,022	$ 51.76		

(1) Represents shares purchased in the open market by American Stock Transfer and Trust Company to satisfy obligations under various equity compensation plans.

(2) Represents shares purchased in the open market by American Stock Transfer and Trust Company to provide shares to participants in the Stock Investment Plan.

(3) Represents shares purchased in the open market by American Stock Transfer and Trust Company and held in a rabbi trust under our Deferred Compensation Plan.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

INTEGRYS ENERGY GROUP, INC.

COMPARATIVE FINANCIAL DATA AND

OTHER STATISTICS (2007 TO 2011)

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)	**2011**	**2010**	**2009**	**2008**	**2007 ***
Total revenues	**$ 4,708.7**	$ 5,203.2	$ 7,499.8	$ 14,047.8	$ 10,292.4
Net income (loss) from continuing operations	**230.9**	223.5	(70.3)	114.8	181.0
Net income (loss) attributed to common shareholders	**227.4**	220.9	(69.6)	116.5	251.3
Total assets	**9,983.2**	9,816.8	11,844.6	14,268.7	11,234.4
Preferred stock of subsidiary	**51.1**	51.1	51.1	51.1	51.1
Long-term debt (excluding current portion)	**1,872.0**	2,161.6	2,394.7	2,285.7	2,265.1
Average shares of common stock					
Basic	**78.6**	77.5	76.8	76.7	71.6
Diluted	**79.1**	78.0	76.8	77.0	71.8
Earnings (loss) per common share (basic)					
Net income (loss) from continuing operations	**$ 2.90**	$ 2.85	$ (0.95)	$ 1.46	$ 2.49
Earnings (loss) per common share (basic)	**2.89**	2.85	(0.91)	1.52	3.51
Earnings (loss) per common share (diluted)					
Net income (loss) from continuing operations	**2.88**	2.83	(0.95)	1.45	2.48
Earnings (loss) per common share (diluted)	**2.87**	2.83	(0.91)	1.51	3.50
Dividends per common share declared	**2.72**	2.72	2.72	2.68	2.56
Stock price at year-end	**$ 54.18**	$ 48.51	$ 41.99	$ 42.98	$ 51.69
Book value per share	**$ 38.01**	$ 37.57	$ 37.51	$ 40.66	$ 42.58
Return on average equity	**7.7%**	7.7%	(2.4)%	3.6%	8.5%
Number of common stock shareholders	**28,993**	30,352	32,755	34,016	35,212
Number of employees	**4,619**	4,612	5,025	5,191	5,231

* Includes the impact of the PELLC merger on February 21, 2007.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIALCONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

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

Strategic Overview

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

The essential components of our business strategy are:

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

- An accelerated annual investment in natural gas distribution facilities (primarily replacement of cast iron mains) at PGL.

- WPS s continued investment in environmental projects to improve air quality and meet the requirements set by environmental regulators. Capital projects to construct and/or upgrade equipment to meet or exceed required environmental standards are planned each year.

- Our approximate 34% ownership interest in ATC, a transmission company that had over $3.0 billion of transmission assets at December 31, 2011. ATC plans to invest approximately $3.8 billion to $4.4 billion 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*.

Continuing Emphasis on 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. Ensuring continued reliability for our customers, we strive to effectively operate a mixed portfolio of generation assets and invest in new generation and natural gas distribution assets, while maintaining or exceeding environmental standards. This allows us to provide a safe, reliable, value-priced service to our customers. We concentrate our efforts on improving and operating efficiently in order to reduce costs and maintain a low risk profile. We actively evaluate opportunities for adding more renewable generation to provide additional environmentally sound energy to our portfolio. Our recent entry into the compressed natural gas fueling marketplace, while not currently significant, is complementary to our existing businesses and is consistent with our mission.

Operating a Nonregulated Energy Services Business Segment with a Controlled Risk and Capital Profile Through our nonregulated Integrys Energy Services subsidiary, we provide retail natural gas and electric products to end-use customers in the northeast quadrant of the United States. In addition, Integrys Energy Services continues to develop, acquire, own and operate renewable energy projects, primarily distributed solar generation, in the United States. We have repositioned this subsidiary from a focus on significant growth in wholesale and retail electric markets across the United States and Canada, to a focus on operating within select retail electric and natural gas markets in our current market footprint where we have experience and believe we will have the most success growing our recurring customer based business. The current strategy is intended to result in more dependable cash and earnings contributions with a controlled risk and capital profile.

Integrating Resources to Provide Operational Excellence We are committed to integrating resources of all our businesses, while meeting all applicable legal and regulatory requirements. This will provide the best value to customers and shareholders by leveraging the individual capabilities and expertise of each business and lowering costs. Operational Excellence initiatives are implemented to encourage top performance in the areas of project management, process improvement, contract administration, and compliance in order to reduce costs and manage projects and activities within appropriate budgets, schedules, and regulations.

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

Table of Contents

are no longer strategic to ongoing operations, are not performing as intended, or have an unacceptable risk profile. We maintain a portfolio approach to risk and earnings.

Our risk management strategy includes the management of market, credit, liquidity, and operational risks through the normal course of business. Forward purchases and sales of electric capacity, energy, natural gas, and other commodities and the use of derivative financial instruments, including commodity swaps and options, provide opportunities 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 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Natural gas utility operations	**$ 103.3**	$ 84.0	$ (172.1)	23.0%	N/A
Electric utility operations	**100.5**	109.8	88.9	(8.5)%	23.5%
Electric transmission investment	**47.8**	46.2	45.5	3.5%	1.5%
Integrys Energy Services operations	**(6.1)**	3.3	3.8	N/A	(13.2)%
Holding company and other operations	**(18.1)**	(22.4)	(35.7)	(19.2)%	(37.3)%
Net income (loss) attributed to common shareholders	**$ 227.4**	$ 220.9	$ (69.6)	2.9%	N/A
Basic earnings (loss) per share	**$ 2.89**	$ 2.85	$ (0.91)	1.4%	N/A
Diluted earnings (loss) per share	**$ 2.87**	$ 2.83	$ (0.91)	1.4%	N/A
Average shares of common stock					
Basic	**78.6**	77.5	76.8	1.4%	0.9%
Diluted	**79.1**	78.0	76.8	1.4%	1.6%

2011 Compared with 2010

Our earnings for 2011 were $227.4 million, compared with $220.9 million for 2010. The $6.5 million increase in earnings was driven by:

- The $31.8 million after-tax decreases in impairment losses recorded on generation plants and losses on dispositions at Integrys Energy Services.

- An additional $20.3 million after-tax net decrease in operating expenses across all segments, driven by a decrease in employee benefit costs and lower depreciation and amortization expense.

- The $15.0 million positive year-over-year impact of tax adjustments recorded in 2011 and 2010 in connection with the federal health care reform.

- A $14.4 million after-tax increase in Integrys Energy Services   realized margins.

These increases were partially offset by:

- A $66.1 million after-tax decrease in Integrys Energy Services   margins from non-cash derivative and inventory fair value adjustments.

- An $8.4 million after-tax decrease in electric utility margins, mainly caused by differences in WPS s 2011 electric rate order compared with the previous rate order.

2010 Compared with 2009

We recognized net income attributed to common shareholders of $220.9 million in 2010 compared with a net loss attributed to common shareholders of $69.6 million in 2009. The primary driver of the $290.5 million increase in earnings was an after-tax noncash goodwill impairment loss of $248.8 million recorded in 2009, compared with no goodwill impairment losses in 2010. Other factors contributing to the increase were the combined approximate $69 million after-tax positive impact on margins of electric and natural gas distribution rate increases effective in 2010, and a $22.5 million after-tax reduction in restructuring expenses year over year. These increases in earnings were partially offset by after-tax impairment charges of $25.9 million in 2010 related to three natural gas-fired generation plants at Integrys Energy Services.

Table of Contents

Regulated Natural Gas Utility Segment Operations

(Millions, except degree days)	2011	Year Ended December 31 2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,998.0**	$ 2,057.2	$ 2,237.5	(2.9)%	(8.1)%
Purchased natural gas costs	**1,101.4**	1,152.0	1,382.0	(4.4)%	(16.6)%
Margins	**896.6**	905.2	855.5	(1.0)%	5.8%
Operating and maintenance expense	**523.6**	542.1	532.6	(3.4)%	1.8%
Goodwill impairment loss			291.1	N/A	(100.0)%
Restructuring expense		(0.2)	6.9	(100.0)%	N/A
Depreciation and amortization expense	**126.1**	130.9	106.1	(3.7)%	23.4%
Taxes other than income taxes	**35.6**	34.4	33.4	3.5%	3.0%
Operating income (loss)	**211.3**	198.0	(114.6)	6.7%	N/A
Miscellaneous income	**2.2**	1.6	3.1	37.5%	(48.4)%
Interest expense	**(48.4)**	(49.7)	(52.2)	(2.6)%	(4.8)%
Other expense	**(46.2)**	(48.1)	(49.1)	(4.0)%	(2.0)%
Income (loss) before taxes	**$ 165.1**	$ 149.9	$ (163.7)	10.1%	N/A
Retail throughput in therms					
Residential	**1,541.5**	1,496.4	1,602.8	3.0%	(6.6)%
Commercial and industrial	**469.5**	455.5	501.4	3.1%	(9.2)%
Other	**61.3**	53.7	60.8	14.2%	(11.7)%
Total retail throughput in therms	**2,072.3**	2,005.6	2,165.0	3.3%	(7.4)%
Transport throughput in therms					
Residential	**237.4**	224.4	237.7	5.8%	(5.6)%
Commercial and industrial	**1,559.7**	1,504.0	1,403.9	3.7%	7.1%
Total transport throughput in therms	**1,797.1**	1,728.4	1,641.6	4.0%	5.3%
Total throughput in therms	**3,869.4**	3,734.0	3,806.6	3.6%	(1.9)%
Weather					
Average heating degree days	**6,675**	6,440	7,061	3.6%	(8.8)%

2011 Compared with 2010

Margins

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 revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 7% decrease in the average per-unit cost of natural gas sold during 2011, which had no impact on margins.

Regulated natural gas utility segment margins decreased $8.6 million. The decrease in margins was driven by the approximate $19 million negative year-over-year impact at PGL and NSG of higher regulatory refunds and lower regulatory recoveries that are offset by equal decreases in operating and maintenance expense, resulting in no impact on earnings. We refunded approximately $13 million more to customers under bad debt riders in 2011. We also recovered approximately $6 million less for environmental cleanup costs at our former manufactured gas plant sites in 2011. See Note 26, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders and Note 16, *Commitment and Contingencies*, for more information on our manufactured gas plant sites.

Table of Contents

The decrease in margins was partially offset by:

- An approximate $4 million net increase in margins as a result of a 3.6% increase in volumes sold.

- Higher sales volumes excluding the impact of weather resulted in approximately $17 million of additional margins. We attribute this increase to a combination of higher use per customer, higher average customer counts, and improved economic conditions for certain customers.

- Colder weather during 2011, as shown by the 3.6% increase in heating degree days, drove an approximate $6 million increase in margins.

- Partially offsetting these increases was an approximate $19 million decrease due to decoupling mechanisms at certain natural gas utilities. Although decoupling was implemented to minimize the impact of changes in sales volumes, it does not cover all jurisdictions or customers. During 2011, decoupling lessened the positive impact from some of the increased sales volumes through higher future customer refunds. During 2010, decoupling lessened the negative impact from some of the decreased sales volumes through higher future customer recoveries.

- An approximate $4 million net increase in margins from rate orders. See Note 26, *Regulatory Environment,* for more information on these rate orders.

- MERC s conservation improvement program (CIP) rate increase, effective November 1, 2010, and its interim natural gas distribution rate increase, effective February 1, 2011, had a combined approximate $13 million positive impact on margin. The CIP margins of approximately $7 million did not impact earnings as they were offset by an increase in operating and maintenance expense.

- The rate increases at PGL and NSG, effective January 28, 2010, and other impacts of rate design, had an approximate $7 million net positive impact on margins.

- The rate decrease at WPS, effective January 14, 2011, resulted in an approximate $16 million negative impact on margins.

- An approximate $2 million increase in margins due to a year-over-year positive impact from the 2010 amortization of a regulatory asset at WPS related to energy efficiency legislation implemented in a prior year.

- An approximate $2 million increase in margins due to a rider approved through September 30, 2011 for recovery of AMRP costs at PGL. See Note 26, *Regulatory Environment,* for more information on this rider.

Operating Income

Operating income at the regulated natural gas utility segment increased $13.3 million. This increase was primarily driven by a $21.9 million decrease in operating expenses, partially offset by the $8.6 million decrease in margins discussed above.

The decrease in operating expenses primarily related to:

- An approximate $19 million decrease due to higher amortization of regulatory liabilities related to bad debt riders and lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites, all at PGL and NSG. Margins decreased by an equal amount, resulting in no impact on earnings.

- A $4.8 million decrease in depreciation and amortization expense. WPS received approval for lower depreciation rates from the PSCW, effective January 1, 2011. The decrease also reflects the impact of a $2.5 million write-off of certain MGU assets in 2010, which is currently pending appeal before the Michigan Court of Appeals.

- A $7.8 million decrease in employee benefits expense, partially driven by lower employee health care costs.

- A $3.6 million decrease in customer accounts expense resulting from lower customer call volumes and a decrease in labor associated with fewer disconnections.

- A $2.6 million decrease in asset usage charges from IBS related to retirement of certain computer hardware.

Table of Contents

- These decreases were partially offset by:

- A $10.0 million increase in natural gas distribution costs. The increase was partially due to additional labor related to distribution operations activities and additional consulting costs associated with a work asset management system and the AMRP. Transportation costs, building maintenance, meter maintenance projects, and other miscellaneous distribution costs also contributed to the increase.

- A $5.0 million increase in expenses related to energy conservation and efficiency programs. This net increase includes expenses related to the CIP that were recovered through the MERC rate increase discussed in margins above.

Other Expense

Other expense decreased $1.9 million, driven by a decrease in interest expense on long-term debt. PGL refinanced some of its long-term debt at lower interest rates in the second half of 2010. In addition, WPS did not replace certain senior notes that matured in the third quarter of 2011.

2010 Compared with 2009

Margins

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 revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 9% decrease in the average per-unit cost of natural gas sold during 2010, which had no impact on margins.

Regulated natural gas utility segment margins increased $49.7 million, driven by the approximate $96 million positive impact of rate increases. These rate increases were necessary, in part, to recover higher operating expenses (as discussed below). See Note 26, *Regulatory Environment,* for more information on these rate increases. The rate increases at PGL and NSG had an approximate $77 million positive impact on margins. The rate increase at WPS and MGU had an approximate $13 million and $3 million positive impact on margins, respectively. A rate increase at MERC related to its CIP had an approximate $3 million positive impact on margins. CIP margins are offset by a corresponding increase in operating and maintenance expense and, therefore, had no impact on earnings.

This increase in margins was partially offset by:

- An approximate $28 million decrease in margins resulting from the 1.9% lower volumes sold, related to:

- An approximate $19 million decrease related to warmer weather during 2010, as evidenced by the 8.8% decrease in heating degree days.

- An approximate $19 million decrease related to lower sales volumes excluding the impact of weather. Residential customer sales volumes decreased, which we attribute to energy conservation, efficiency efforts, and general economic conditions. This decrease was partially offset by a net increase in commercial and industrial sales volumes for both retail and transportation customers, driven by certain transportation customers of MERC and MGU.

- Partially offsetting these decreases was the approximate $10 million increase in 2010 due to decoupling mechanisms in place at certain of our regulated natural gas utilities. Under decoupling, certain of our regulated natural gas utilities are allowed to defer the difference between the actual and rate case authorized delivery charge components of margin from certain customers and adjust future rates in accordance with rules applicable to each jurisdiction. The decoupling mechanism for WPS s natural gas utility includes an annual $8.0 million cap for the deferral of any excess or shortfall from the rate case authorized margin. This cap was reached in the first quarter of 2010 but was not reached in 2009.

- An approximate $18 million net decrease in margins driven by lower recovery of environmental cleanup expenditures at our former manufactured gas plant sites, partially offset by an increase in margins related to recoveries received under the PGL and NSG bad debt riders. These amounts were offset by an equal net decrease in operating and maintenance expense resulting from lower net amortization of the related regulatory assets and, therefore, had no impact on earnings. Recoveries under these riders represent net billings to customers of the excess or deficiency of actual 2008 and 2009 bad debt expense over bad debt expense reflected in utility rates during those same periods. See Note 26, *Regulatory Environment*, for more information on the PGL and NSG bad debt riders.

Table of Contents

Operating Income (Loss)

Operating income at the regulated natural gas utility segment increased $312.6 million. This increase was primarily driven by the positive impact of a $291.1 million noncash goodwill impairment loss that was recorded in the first quarter of 2009. Also contributing to the increase was the $49.7 million increase in the natural gas margins discussed above, partially offset by a $28.2 million increase in other operating expenses. See Note 10, *Goodwill and Other Intangible Assets*, for information related to the goodwill impairment loss recorded in 2009.

The increase in other operating expenses primarily related to:

- A $24.8 million increase in depreciation and amortization expense, primarily due to the ICC s rate order for PGL and NSG, effective January 28, 2010. This rate order allows earlier recovery in rates for net dismantling costs by including them as a component of depreciation rates applied to natural gas distribution assets. The increase also reflects the impact of a $2.5 million write-off of certain MGU assets, which is currently pending appeal before the Michigan Court of Appeals.

- A $12.9 million increase in expenses related to energy conservation programs and enhanced efficiency initiatives. This increase includes expenses related to the CIP that were recovered through the MERC rate increase discussed in margins above.

- A $14.7 million increase in employee benefit costs, primarily driven by an increase in other postretirement benefit costs.

- A $7.4 million increase in asset usage charges from IBS related to implementation of both a work asset management system for natural gas operations and an upgrade to an enterprise resource planning system for finance and supply chain services.

- These increases were partially offset by:

- An approximate $18 million net decrease due to approximately $25 million of lower amortization of the regulatory asset related to environmental cleanup expenditures for manufactured gas plant sites, partially offset by approximately $7 million of amortization related to the regulatory assets recorded as a result of the PGL and NSG bad debt riders. This net decrease was passed through to customers in rates and, therefore, had no impact on earnings.

- A $7.1 million decrease in restructuring expenses related to a reduction in workforce. See Note 3, *Restructuring Expense,* for more information.

- A $6.1 million decrease in labor costs as a result of the reduction in workforce and company-wide furloughs implemented as a part of previously announced cost management efforts.

Table of Contents

Regulated Electric Utility Segment Operations

(Millions, except degree days)	2011	Year Ended December 31 2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,307.3**	$ 1,338.9	$ 1,301.6	(2.4)%	2.9%
Fuel and purchased power costs	**546.3**	563.9	584.5	(3.1)%	(3.5)%
Margins	**761.0**	775.0	717.1	(1.8)%	8.1%
Operating and maintenance expense	**421.5**	417.2	392.0	1.0%	6.4%
Restructuring expense	**0.2**	(0.3)	8.6	N/A	N/A
Depreciation and amortization expense	**88.5**	94.7	90.3	(6.5)%	4.9%
Taxes other than income taxes	**47.6**	45.6	46.6	4.4%	(2.1)%
Operating income	**203.2**	217.8	179.6	(6.7)%	21.3%
Miscellaneous income	**0.8**	1.5	4.8	(46.7)%	(68.8)%
Interest expense	**(41.8)**	(43.9)	(41.6)	(4.8)%	5.5%
Other expense	**(41.0)**	(42.4)	(36.8)	(3.3)%	15.2%
Income before taxes	**$ 162.2**	$ 175.4	$ 142.8	(7.5)%	22.8%
Sales in kilowatt-hours					
Residential	**3,135.6**	3,114.3	3,043.0	0.7%	2.3%
Commercial and industrial	**8,520.9**	8,439.6	8,155.5	1.0%	3.5%
Wholesale	**4,256.8**	4,994.7	5,079.1	(14.8)%	(1.7)%
Other	**38.4**	39.1	40.0	(1.8)%	(2.3)%
Total sales in kilowatt-hours	**15,951.7**	16,587.7	16,317.6	(3.8)%	1.7%
Weather WPS:					
Heating degree days	**7,524**	7,080	7,962	6.3%	(11.1)%
Cooling degree days	**603**	616	274	(2.1)%	124.8%
Weather UPPCO:					
Heating degree days	**8,676**	8,002	9,317	8.4%	(14.1)%
Cooling degree days	**305**	301	99	1.3%	204.0%

2011 Compared with 2010

Margins

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric utility margins provide a more meaningful basis for evaluating utility operations than electric 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. Any significant changes in fuel and purchased power costs that are not recovered from customers are explained in the margin discussion below.

Regulated electric utility segment margins decreased $14.0 million, driven by:

- An approximate $18 million decrease in retail margins due to differences between the 2011 WPS rate order and the previous rate order. Although the 2011 rate order included a lower authorized return on common equity, lower rate base, and other reduced costs, which resulted in lower total revenues and margins, the rate order also projected lower total sales volumes, which led to a rate increase on a per-unit basis. The 2011 rate increase, calculated on a per unit basis, was more than offset by the decoupling mechanism due to changes in the rate order that impact the decoupling calculation. For more details on the WPS 2011 rate order, see Note 26, *Regulatory Environment*.

- An approximate $5 million decrease in margins from wholesale customers. The decrease was due to lower sales volumes and lower non-fuel revenue requirements driven by a lower return on common equity, lower rate base, and other reduced costs.

- These decreases were partially offset by:

- An approximate $6 million increase in margins driven by a retail electric rate increase at UPPCO.

Table of Contents

- An approximate $3 million increase in margins due to a year-over-year positive impact from the 2010 amortization of a regulatory asset at WPS related to energy efficiency legislation implemented in a prior year.

Operating Income

Operating income at the regulated electric utility segment decreased $14.6 million, driven by the $14.0 million decrease in margins and a $0.6 million increase in operating expenses.

The increase in operating expenses was primarily related to:

- A $4.9 million increase in the amortization of various regulatory deferrals. This increase was offset in revenues, resulting in no impact on earnings.

- A $3.6 million increase in customer assistance expense related to payments made to the Focus on Energy program. The program promotes residential and small business energy efficiency and renewable energy products.

- A $2.0 million increase in taxes other than income taxes, driven by increases in gross receipts taxes and property taxes.

- A $1.9 million increase in electric transmission expense.

- A $1.8 million increase in injuries and damages expenses.

- These increases were substantially offset by:

- A $7.7 million decrease in employee benefit costs. The decrease was partially due to lower pension expense driven by an increase in contributions, which increased plan assets.

- A $6.2 million decrease in depreciation and amortization expense. The PSCW approved lower depreciation rates effective January 1, 2011, and we had lower software amortization in 2011.

<u>Other Expense</u>

Other expense decreased $1.4 million, driven by a decrease in interest expense due to the maturity and repayment of $150 million of long-term debt at WPS in August 2011.

2010 Compared with 2009

<u>Margins</u>

Electric margins are defined as electric operating revenues less fuel and purchased power costs. Management believes that electric margins provide a more meaningful basis for evaluating electric utility operations than electric 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. Any significant changes in fuel and purchased power costs that are not recovered from customers are explained in the margin discussion below.

Regulated electric utility segment margins increased $57.9 million, driven by:

- An approximate $26 million increase in margins driven by lower fuel and purchased power costs incurred during 2010 as compared with authorized fuel and purchased power cost recovery rates.

- An approximate $21 million combined positive impact of retail electric rate increases at both WPS and UPPCO, effective January 1, 2010.

- An approximate $7 million increase in margins due to a 2.7% increase in sales volumes to residential customers at WPS, primarily related to warmer year-over-year weather during the cooling season, as evidenced by the increase in cooling degree days. Margins were impacted by the year-over-year increase in sales volumes because WPS reached the annual $14.0 million electric decoupling cap in the second quarter of 2010 and 2009 and remained over the cap through the end of both years. Therefore, no additional decoupling deferral was allowed for additional shortfalls from authorized margin for the remainder of both years. Under decoupling, WPS is allowed to defer (up to the established cap) the difference between its actual margin and the rate case authorized margin recognized from residential and small commercial and industrial customers.

Table of Contents

- An approximate $7 million increase in margins due to a 7.5% increase in sales volumes to large commercial and industrial customers at WPS, primarily related to changes in the business operations of these customers year over year.

- These increases in regulated electric utility segment margins were partially offset by an approximate $2 million decrease in margins from WPS s wholesale customers, primarily due to a decrease in sales volumes.

Operating Income

Operating income at the regulated electric utility segment increased $38.2 million, driven by the $57.9 million increase in margins, partially offset by a $19.7 million increase in operating expenses.

The increase in operating expenses was the result of:

- A $13.9 million increase in electric transmission expense.

- A $12.7 million increase in customer assistance expense related to payments made to the Focus on Energy program. The program promotes residential and small business energy efficiency and renewable energy products.

- A $7.5 million increase in employee benefit costs. The increase was partially due to an increase in pension and other postretirement benefit expenses, driven by the amortization of negative investment returns on plan assets from prior years.

- A $4.4 million increase in depreciation and amortization expense, primarily related to the Crane Creek Wind Farm being placed in service for accounting purposes in December 2009.

- These increases were partially offset by:

- An $8.9 million year-over-year decrease in restructuring expenses related to a reduction in workforce. See Note 3, *Restructuring Expense*, for more information.

- A $6.2 million decrease in labor costs, driven by the reduction in workforce and company-wide furloughs implemented as part of previously announced cost management efforts.

- A $2.1 million decrease in electric maintenance expense at WPS, primarily related to a greater number of planned outages at its generation plants during 2009 compared with 2010.

Other Expense

Other expense at the regulated electric utility segment increased $5.6 million, driven by a decrease in AFUDC, primarily related to the construction of the Crane Creek Wind Farm in 2009.

Electric Transmission Investment Segment Operations

2011 Compared with 2010

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $1.5 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. We earn higher returns each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits.

2010 Compared with 2009

Miscellaneous Income

Miscellaneous income at the electric transmission investment segment increased $2.3 million. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. We earn higher returns each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits.

Table of Contents

Integrys Energy Services Nonregulated Segment Operations

(Millions, except natural gas sales volumes)	Year Ended December 31 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Revenues	**$ 1,395.9**	$ 1,823.7	$ 3,994.0	(23.5)%	(54.3)%
Cost of sales	**1,272.7**	1,614.3	3,696.1	(21.2)%	(56.3)%
Margins	**123.2**	209.4	297.9	(41.2)%	(29.7)%
Margin Detail					
Realized retail electric margins	**98.5**	85.4(2)(4)	82.0(4)	15.3%	4.1%
Realized wholesale electric margins	**(0.2)**(1)	(8.2)(3)	40.3	(97.6)%	N/A
Realized energy asset margins	**31.1**	34.5	37.9	(9.9)%	(9.0)%
Fair value accounting adjustments	**(30.7)**	36.0	29.9	N/A	20.4%
Electric and other margins	**98.7**	147.7	190.1	(33.2)%	(22.3)%
Realized retail natural gas margins	**49.1**	50.0(4)	68.7(4)	(1.8)%	(27.2)%
Realized wholesale natural gas margins	**3.9**(1)	(3.3)	40.8	N/A	N/A
Lower-of-cost-or-market inventory adjustments	**(10.7)**	6.8	155.4	N/A	(95.6)%
Fair value accounting adjustments	**(17.8)**	8.2	(157.1)	N/A	N/A
Natural gas margins	**24.5**	61.7	107.8	(60.3)%	(42.8)%
Operating and maintenance expense	**108.8**	117.6	188.6	(7.5)%	(37.6)%
Impairment losses on property, plant, and equipment	**4.6**	43.2	0.7	(89.4)%	6,071.4%
Restructuring expense	**1.8**	8.3	27.2	(78.3)%	(69.5)%
Net (gain) loss on Integrys Energy Services dispositions related to strategy change	**(0.3)**	14.1	28.9	N/A	(51.2)%
Depreciation and amortization	**12.7**	17.2	19.0	(26.2)%	(9.5)%
Taxes other than income taxes	**7.0**	5.0	7.4	40.0%	(32.4)%
Operating income (loss)	**(11.4)**	4.0	26.1	N/A	(84.7)%
Miscellaneous income	**0.4**	9.1	6.0	(95.6)%	51.7%
Interest expense	**(2.3)**	(6.7)	(13.1)	(65.7)%	(48.9)%
Other income (expense)	**(1.9)**	2.4	(7.1)	N/A	N/A
Income (loss) before taxes	**$ (13.3)**	$ 6.4	$ 19.0	N/A	(66.3)%
Physically settled volumes					
Retail electric sales volumes in kwh	**12,416.5**	12,647.9(6)	15,045.3(6)	(1.8)%	(15.9)%
Wholesale electric sales volumes in kwh	**320.1**(5)	1,319.9	3,965.2	(75.7)%	(66.7)%
Retail natural gas sales volumes in bcf	**125.5**	133.3(6)	236.7(6)	(5.9)%	(43.7)%
Wholesale natural gas sales volumes in bcf		27.5	402.5	(100.0)%	(93.2)%

kwh kilowatt-hours

bcf billion cubic feet

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

(2) This amount includes negative margin of $1.4 million related to the settlement of retail supply contracts in connection with Integrys Energy Services strategy change.

(3) This amount includes negative margin of $9.3 million related to the settlement of wholesale supply contracts in connection with Integrys Energy Services strategy change.

(4) Amounts include margins in markets that Integrys Energy Services no longer considers strategic.

(5) Primarily relates to electric generation assets.

(6) Includes physically settled volumes in markets that Integrys Energy Services no longer considers strategic.

2011 Compared with 2010

Revenues

Revenues decreased $427.8 million, driven by lower sales volumes resulting from Integrys Energy Services strategy change, and lower year-over-year average commodity prices.

Table of Contents

Margins

Integrys Energy Services margins decreased $86.2 million. The significant items contributing to the change in margins were as follows:

Electric and Other Margins

Realized retail electric margins

Realized retail electric margins increased $13.1 million. Higher margins in the markets that Integrys Energy Services continues to focus on drove the increase. Most of these markets had higher sales volumes and positive results from the change in pricing and customer mix that was implemented as part of Integrys Energy Services strategy change. The $1.4 million negative impact on margins in 2010 from the settlement of supply contracts also contributed to the year-over-year increase. The increase was partially offset by a decrease in margins related to the sale of the Texas retail electric business in June 2010, resulting from Integrys Energy Services strategy change.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $66.7 million decrease in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $0.9 million. In 2011 there were fewer opportunities to take advantage of natural gas price volatility and changes in market prices for natural gas storage and transportation capacity.

Inventory accounting adjustments

Integrys Energy Services physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $17.5 million year-over-year decrease in margins from inventory adjustments was driven by an increase in write-downs and lower volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $26.0 million decrease in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income (Loss)

Integrys Energy Services operating income decreased $15.4 million, driven by the $86.2 million decrease in margins discussed above, partially offset by a $70.8 million decrease in operating expenses.

The decrease in operating expense was primarily related to:

- A $38.6 million decrease in impairment losses recorded on generation plants.

- A $14.4 million decrease due to losses on Integrys Energy Services dispositions in 2010 related to its strategy change.

- A $6.5 million decrease in restructuring expense.

- A $4.5 million decrease in depreciation and amortization expense, driven by lower book value of the generation plants for which impairment losses were recorded in 2010.

Table of Contents

- A $4.7 million decrease in employee payroll and benefit related expenses, primarily due to the reduction in workforce associated with Integrys Energy Services strategy change.

- A $2.2 million decrease in intercompany fees related to a credit agreement with the holding company.

Other Income (Expense)

Integrys Energy Services other income decreased $4.3 million. The main driver for the decrease was an $8.7 million decrease in miscellaneous income. This decrease was driven by the negative year-over-year impact of a $4.3 million gain reclassified from accumulated OCI in 2010 related to foreign currency translation adjustments, and a $3.4 million decrease in interest income driven by the holding company s repayment of borrowings from Integrys Energy Services in the first quarter of 2011. The decrease in miscellaneous income was partially offset by a $4.4 million decrease in interest expense driven by reduced business size as a result of Integrys Energy Services strategy change.

2010 Compared with 2009

Revenues

Revenues decreased $2,170.3 million during 2010, compared with 2009, as a result of our decision to reduce the scale, scope, and risk attributes of Integrys Energy Services by focusing on selected retail electric and natural gas markets in the United States and investments in energy assets with renewable attributes. See Note 5, *Dispositions*, for a discussion of the dispositions completed in connection with Integrys Energy Services strategy change. Also contributing to the decrease in revenues were lower energy prices, as the average market price of natural gas and electricity decreased approximately 7% and 4% respectively, year over year.

Margins

Integrys Energy Services margins decreased $88.5 million during 2010, compared with 2009. The significant items contributing to the change in margins were as follows:

Electric and Other Margins

Realized retail electric margins

Realized retail electric margins increased $3.4 million during 2010, compared with 2009, driven by:

- A $9.2 million increase in margins in the Illinois market, primarily driven by a change in pricing methodology and customer mix that was implemented as part of Integrys Energy Services strategy change.

- A $5.5 million increase in margins in the Michigan market. This increase was driven by higher sales volumes due to increased marketing efforts.

- The above increases in realized retail electric margins were partially offset by a $9.0 million decrease in margins related to the sale of the Texas retail electric business in June 2010, driven by reduced sales volumes and a $1.4 million decrease related to the settlement of supply contracts. See Note 5, *Dispositions*, for a discussion of this sale.

<u>Realized wholesale electric margins</u>

Realized wholesale electric margins decreased $48.5 million year over year, including negative margins of $9.3 million in 2010 related to the settlement of wholesale supply contracts in connection with Integrys Energy Services strategy change. Wholesale transactions and structured origination activity were significantly scaled back in conjunction with Integrys Energy Services sale of substantially all of its United States wholesale electric marketing and trading business, which was completed in February 2010. See Note 5, *Dispositions*, for more information on Integrys Energy Services sale of its United States wholesale electric marketing and trading business.

<u>Fair value accounting adjustments</u>

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $6.1 million increase in electric margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts.

Table of Contents

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $18.7 million during 2010, compared with 2009, driven by:

- A $7.6 million decrease driven by reduced sales volumes due to the sale of Integrys Energy Services Canadian retail natural gas portfolio in September 2009. See Note 5, *Dispositions*, for a discussion of this sale.

- A $7.5 million decrease in margins in the Illinois market, primarily due to the negative year-over-year impact of the withdrawal of a significant amount of natural gas from storage in the first half of 2009, resulting in higher realized margins during that period. Also contributing to the decrease were lower sales volumes resulting from Integrys Energy Services strategy change.

Realized wholesale natural gas margins

Realized wholesale natural gas margins decreased $44.1 million year over year due to Integrys Energy Services completing the sale of substantially all of its wholesale natural gas business in December 2009. Additional components of the wholesale natural gas business were sold in March 2010 and May 2010. The remaining realized wholesale natural gas activity at Integrys Energy Services is related to residual contracts that will settle in the first half of 2011. The risks associated with these residual contracts are economically hedged. See Note 5, *Dispositions*, for more information on Integrys Energy Services sale of its wholesale natural gas business.

Inventory accounting adjustments

Integrys Energy Services physical natural gas inventory is valued at the lower of cost or market. When the market price of natural gas is lower than the carrying value of the inventory, write-downs are recorded within margins to reflect inventory at the end of the period at its net realizable value. These write-downs result in higher margins in future periods as the inventory that was written down is sold. The $148.6 million year-over-year decrease in margins from inventory adjustments was driven by a lower volume of inventory withdrawn from storage in 2010 for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $165.3 million increase in natural gas margins year over year. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts.

Operating Income (Loss)

Integrys Energy Services operating income decreased $22.1 million year over year, driven by the $88.5 million decrease in margins discussed above, and a $43.2 million noncash impairment loss related to three natural gas-fired generation plants in the third quarter of 2010. These decreases were partially offset by a $71.0 million decrease in operating and maintenance expense, an $18.9 million decrease in restructuring expense, and a $14.8 million decrease in the net loss on Integrys Energy Services dispositions related to its strategy change (which primarily resulted from mark-to-market timing differences that have historically caused earnings volatility at Integrys Energy Services).

The decrease in operating and maintenance expense was driven by:

- A $46.0 million year-over-year decrease in employee payroll and benefit related expenses, primarily due to the reduction in workforce associated with Integrys Energy Services strategy change.

- A $10.5 million year-over-year decrease in bad debt expense driven by the partial recovery in 2010 of receivables fully reserved in prior years, and a decrease in reserves resulting from reduced business activity.

- The $9.0 million positive year-over-year impact of a fee incurred in the second quarter of 2009 related to an agreement with a counterparty that enabled Integrys Energy Services to reduce collateral support requirements.

- An $8.0 million year-over-year decrease in broker commissions, contractor expenses, and various other fees, resulting from reduced business activity associated with Integrys Energy Services strategy change.

- The above decreases in operating and maintenance expense were partially offset by $8.1 million of intercompany fees related to a credit agreement established in 2010 with the holding company.

Table of Contents

Other Income (Expense)

Integrys Energy Services other income increased $9.5 million year over year, driven by a $4.3 million gain reclassified from accumulated other comprehensive income in 2010 related to foreign currency translation adjustments recorded in prior periods, as well as a $6.4 million decrease in interest expense driven by reduced business size, as a result of Integrys Energy Services strategy change.

Holding Company and Other Segment Operations

(Millions)	Year Ended December 31 2011	2010	2009	Change in 2011 Over 2010	Change in 2010 Over 2009
Operating income (loss)	**$ 5.7**	$ 8.3	$ (1.9)	(31.3)%	N/A
Other expense	**(34.0)**	(45.9)	(58.1)	(25.9)%	(21.0)%
Net loss before taxes	**$ (28.3)**	$ (37.6)	$ (60.0)	(24.7)%	(37.3)%

2011 Compared with 2010

Operating Income

Operating income at the holding company and other segment decreased $2.6 million. The decrease was driven primarily by lower intercompany fees charged by the holding company to Integrys Energy Services related to lower interest charges and decreased use of an intercompany credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $11.9 million. Interest expense on long-term debt decreased, driven by both lower interest rates on debt refinanced and lower average outstanding long-term debt in 2011.

2010 Compared with 2009

Operating Income (Loss)

Operating income at the holding company and other segment increased $10.2 million, driven by $8.1 million of intercompany fees charged by the holding company to Integrys Energy Services related to a credit agreement established in 2010.

Other Expense

Other expense at the holding company and other segment decreased $12.2 million, driven by a $14.6 million decrease in external interest expense.

Provision for Income Taxes

	Year Ended December 31		
	2011	**2010**	**2009**
Effective Tax Rate	**36.7%**	39.9%	624.6%

2011 Compared with 2010

Our effective tax rate decreased during 2011. In the fourth quarter of 2011, we reduced the provision for income taxes by $5.8 million when we recorded a regulatory asset related to deferred income taxes previously expensed as part of the 2010 federal health care reform. We were authorized recovery of these income taxes through our recently approved rate order for PGL and NSG. As discussed below, we expensed $10.8 million of deferred income taxes as a result of the federal health care reform in 2010. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform* for more information. The decrease in the effective tax rate during 2011 was partially offset when we increased our provision for income taxes and deferred income tax liabilities by $6.0 million for tax law changes in Michigan and Wisconsin. See *Liquidity and Capital Resources, Other Future Considerations Recent Tax Law Changes* for more information.

Table of Contents

For information on changes in the deferred income tax balances, see Note 15, Income Taxes.

2010 Compared with 2009

Our effective tax rate decreased during 2010. The rate decreased primarily because a significant portion of our $291.1 million noncash pre-tax goodwill impairment loss recorded in 2009 was not deductible for tax purposes. Partially offsetting this decrease in the effective tax rate was the 2010 federal health care reform. This legislation eliminated the tax deduction for retiree prescription drug payments that are paid by employers and are offset by the receipt of a federal Medicare Part D subsidy. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform* for more information. As a result, we expensed $10.8 million of deferred income taxes during 2010. This amount excluded $1.0 million for which UPPCO was authorized recovery from ratepayers.

Discontinued Operations, Net of Tax

2011 Compared with 2010

Income from discontinued operations, net of tax, decreased $0.6 million in 2011. During 2011, we remeasured an unrecognized tax benefit liability related to the 2007 sale of Peoples Energy Production Company, including an adjustment for a lapse in the statute of limitations for certain states associated with these tax filings.

2010 Compared with 2009

Income from discontinued operations, net of tax, decreased $2.6 million in 2010. During 2009, Integrys Energy Services recognized a $3.9 million ($2.4 million after tax) gain on the sale of its energy management consulting business in discontinued operations. During 2010, Integrys Energy Services recorded a $0.2 million after-tax gain in discontinued operations when contingent payments were earned related to the sale of this business.

For more information on the discontinued operations discussed above, see Note 5, *Dispositions,* and Note 27, *Segments of Business*.

LIQUIDITY AND CAPITAL RESOURCES

We believe we have adequate resources to fund ongoing operations and future capital expenditures. These resources include our cash balances, liquid assets, operating cash flows, access to equity and debt capital markets, and available borrowing capacity. 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

2011 Compared with 2010

Net cash provided by operating activities was $721.9 million during 2011, compared with $725.2 million during 2010. The $3.3 million decrease in net cash provided by operating activities was mainly driven by:

- Net cash used for working capital of $34.2 million in 2011, compared with $40.8 million of net cash provided by working capital in 2010. The $75.0 million year-over-year increase in working capital requirements was primarily due to:

- A $17.3 million increase in cash collateral provided to counterparties in 2011, compared with a $163.6 million decrease in cash collateral provided in 2010, primarily due to the change in Integrys Energy Services business related to its strategy change.

- Inventory levels increased $28.0 million in 2011, compared to a decrease of $51.1 million in 2010. The increase in inventory in 2011 was driven by warmer weather at the end of 2011 compared to the end of 2010, which impacted inventory levels at PGL and NSG, and increased coal freight costs at WPS. The decrease in inventory in 2010 was largely due to the impact of the Integrys Energy Services strategy change.

- Partially offsetting these changes was the positive impact from a $46.2 million decrease in other current assets in 2011, compared with an $85.5 million increase in other current assets in 2010. This change was driven by the year-over-year increase in net cash received for income taxes, which was primarily due to the 100% bonus tax depreciation allowed in 2011.

- Also partially offsetting these changes was a $68.4 million year-over-year positive impact from the change in other current liabilities. The change was driven by the return of collateral to counterparties in 2010 as a result of Integrys Energy Services strategy change.

Table of Contents

- The net increase in working capital requirements was partially offset by a $70.3 million net decrease in contributions to pension and other postretirement benefit plans.

2010 Compared with 2009

Net cash provided by operating activities was $725.2 million during 2010, compared with $1,606.3 million during 2009. The $881.1 million decrease in net cash provided by operating activities was mainly driven by:

- A $746.5 million net decrease in cash provided by working capital, driven by:

- A $767.2 million year-over-year decrease in cash generated from customer collections, primarily due to the Integrys Energy Services strategy change, as well as lower year-over-year natural gas prices, which impacted both the regulated natural gas segment and Integrys Energy Services.

- A $393.0 million year-over-year decrease in cash generated from reduced inventory levels, mainly the result of the withdrawal of a significant amount of natural gas from storage at Integrys Energy Services during 2009 in order to improve its liquidity position.

- Partially offsetting these changes was a $578.9 million year-over-year decrease in cash used to pay accounts payable balances, driven by smaller accounts payable balances at Integrys Energy Services as a result of the strategy change, as well as lower year-over-year natural gas prices.

- Also offsetting these changes was a year-over-year increase in cash flows of $118.1 million due to a decrease in cash collateral provided to counterparties, due primarily to the change in Integrys Energy Services business related to its strategy change.

- A $175.8 million year-over-year increase in deferred income taxes and investment tax credits, primarily driven by a change in tax accounting related to capitalization of overhead costs and legislation providing for bonus depreciation during 2010.

- A $148.5 million year-over-year increase in contributions to pension and other postretirement benefit plans.

Investing Cash Flows

2011 Compared with 2010

Net cash used for investing activities was $394.8 million during 2011, compared with $199.7 million during 2010. The $195.1 million increase in net cash used for investing activities was primarily driven by:

- A $58.4 million decrease in proceeds received from the sale or disposal of assets. The proceeds received in 2010 primarily related to the Integrys Energy Services strategy change.
- A $52.6 million increase in cash used to fund capital expenditures (discussed below).
- In 2011, $42.6 million of net cash was used for the acquisition of the Pinnacle and Trillium compressed natural gas fueling businesses.
- A $30.7 million year-over-year increase in capital contributions to equity method investments, mainly due to increased contributions to INDU Solar Holdings, LLC.

2010 Compared with 2009

Net cash used for investing activities was $199.7 million during 2010, compared with $440.7 million during 2009. The $241.0 million decrease in net cash used for investing activities was primarily driven by:

- A $185.4 million decrease in cash used to fund capital expenditures (discussed below).
- A $27.2 million year-over-year decrease in capital contributions to equity method investments, mainly related to ATC capital contributions.
- A year-over-year increase in proceeds received from the sale or disposal of assets, primarily related to Integrys Energy Services strategy change. For more information on these dispositions, see Note 5, *Dispositions*.

Table of Contents

Capital Expenditures

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

Reportable Segment (millions)	2011	2010	2009
Electric utility	**$ 84.1**	$ 87.2	$ 250.4
Natural gas utility	**199.3**	133.6	136.9
Integrys Energy Services	**18.0**	15.2	22.4
Holding company and other	**10.0**	22.8	34.5
Integrys Energy Group consolidated	**$ 311.4**	$ 258.8	$ 444.2

The increase in capital expenditures at the natural gas utility segment in 2011 compared with 2010 was primarily a result of the AMRP at PGL. Partially offsetting this increase was a decrease in capital expenditures at the holding company and other segment, primarily due to lower software project expenditures in 2011.

The decrease in capital expenditures at the electric utility segment in 2010 compared with 2009 was primarily due to decreased expenditures related to the Crane Creek Wind Farm project, which was placed in service for accounting purposes in December 2009. The decrease in capital expenditures at the holding company and other segment was mainly due to lower expenditures in 2010 related to software projects.

Financing Cash Flows

2011 Compared with 2010

Net cash used for financing activities was $478.4 million during 2011, compared with $391.4 million during 2010. The $87.0 million increase in net cash used for financing activities was primarily driven by:

- A $648.6 million increase due to $515.8 million of net repayments of long-term debt in 2011, compared with $132.8 million of net long-term issuances in 2010.
- A $28.3 million decrease in cash provided by the issuance of common stock. See *Significant Financing Activities* for more information.
- A $20.3 million increase in cash used for the payment of common stock dividends.
- A $15.4 million decrease in net proceeds from the sale of borrowed natural gas related to the strategy change at Integrys Energy Services.

Partially offsetting these increases in net cash used were:

- A $505.4 million decrease due to $293.3 million of net borrowings of short-term debt and notes payable in 2011, compared with $212.1 million of net repayments in 2010.
- A $125.9 million decrease in payments related to the divestitures of the nonregulated wholesale electric and natural gas businesses. In 2010, $27.8 million was paid to the buyers upon the sale of these businesses. No such payments were made in 2011. The remaining $98.1 million decrease related to the settlement of certain contracts that were executed at the time of sale.

2010 Compared with 2009

Net cash used for financing activities was $391.4 million during 2010, compared with $1,378.4 million during 2009. The $987.0 million year-over-year decrease in net cash used for financing activities was primarily driven by:

- A $761.5 million year-over-year decrease in the net repayment of short-term borrowings.
- A $298.6 million decrease due to net natural gas loan proceeds at Integrys Energy Services of $15.4 million during 2010, compared with the net repayment of $283.2 million of natural gas loans during 2009.

Table of Contents

- Partially offsetting these changes were $157.8 million of payments made during 2010 to buyers of the wholesale natural gas and electric businesses and payments for settlement of out-of-the-money transactions that were executed at the time of sale, compared with $33.9 million of proceeds received upon the sale of substantially all of the wholesale natural gas business during 2009. The out-of-the-money transactions were replacement supply trades for the retained retail operations and were transacted at the original transfer price between Integrys Energy Services wholesale and retail businesses. Payments made to the buyers to settle the replacement supply contracts were funded with proceeds received from the settlement of the related retail electric and retail natural gas sales contracts.

Significant Financing Activities

Our quarterly common stock dividend of $0.68 per share in 2011 remained the same as in 2010.

From January 1, 2010 through February 10, 2010, shares were purchased on the open market to meet the requirements of our Stock Investment Plan and certain stock-based employee benefit and compensation plans. From February 11, 2010 through April 30, 2011, we issued new shares of common stock to meet the requirements of these plans. Beginning May 1, 2011, shares were again purchased on the open market to meet the requirements of these plans.

We had $303.3 million in outstanding commercial paper borrowings at December 31, 2011, and none outstanding at December 31, 2010. We had no short-term notes payable outstanding at December 31, 2011, and $10.0 million outstanding at December 31, 2010. We had no borrowings under revolving credit facilities at December 31, 2011, and 2010. See Note 12, *Short-Term Debt and Lines of Credit,* for more information.

For information on the issuance and redemption of our long-term debt and that of our subsidiaries, see Note 13, *Long-Term Debt*.

We use internally generated funds, commercial paper borrowings, and other short-term borrowings to satisfy most of our capital requirements. We also periodically issue long-term debt and common stock to reduce short-term debt, maintain desired capitalization ratios, and fund future growth.

We have our own commercial paper borrowing programs, as do WPS and PGL.

WPS periodically issues long-term debt to reduce short-term debt, fund future growth, and maintain capitalization ratios as authorized by the PSCW.

PGL and NSG periodically issue long-term debt in order to reduce short-term debt, refinance maturing securities, maintain desired capitalization ratios, and fund future growth. The specific forms of long-term financing, amounts, and timing depend on business needs, market conditions, and other factors.

Table of Contents

Credit Ratings

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

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

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

On January 24, 2012, Standard & Poor s raised the issuer credit ratings for us, PGL, and NSG to A- from BBB+. In addition, they raised our senior unsecured debt rating to BBB+ from BBB and raised our junior subordinated notes rating to BBB from BBB-. The outlook for us, PGL, and NSG was revised to stable from positive. According to Standard & Poor s, the revised ratings reflect their view that our business risk profile improved to excellent from strong and that we continue to have a significant financial risk profile. The revised business risk profile assessment reflects the successful implementation of our strategic initiative to reduce our exposure to the nonutility businesses and our effective management of regulatory risk. WPS s outlook remained stable.

On May 27, 2010, Moody s revised the outlook for us and all of our subsidiaries to stable from negative. According to Moody s, the revised outlook reflected a reduced business risk profile driven by the recently completed restructuring of Integrys Energy Services into a smaller segment with significantly reduced collateral requirements. Moody s also raised the following ratings of our subsidiaries:

- The senior secured debt rating and first mortgage bonds rating of WPS were raised from A1 to Aa3.
- The senior secured debt ratings of PGL and NSG were raised from A2 to A1.

According to Moody s, the upgrade follows the August 2009 upgrade of the senior secured ratings of the majority of its investment grade regulated utilities (issuers with negative outlooks were excluded from the August 2009 upgrade).

Table of Contents

Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2011, including those of our subsidiaries.

(Millions)	Total Amounts Committed	2012	Payments Due By Period 2013 to 2014	2015 to 2016	2017 and Thereafter
Long-term debt principal and interest payments (1)	$ 2,975.2	$ 358.1	$ 581.0	$ 633.9	$ 1,402.2
Operating lease obligations	81.6	8.5	13.8	8.1	51.2
Commodity purchase obligations (2)	2,669.0	700.5	707.7	345.6	915.2
Capital contributions to equity method investment	3.4	3.4			
Purchase orders (3)	418.2	416.8	1.4		
Pension and other postretirement funding obligations (4)	820.6	289.5	201.1	60.0	270.0
Total contractual cash obligations	$ 6,968.0	$ 1,776.8	$ 1,505.0	$ 1,047.6	$ 2,638.6

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

(2) Energy and related commodity supply contracts at Integrys Energy Services included as part of commodity purchase obligations are generally entered into to meet obligations to deliver energy and related products to customers. The utility subsidiaries expect to recover the costs of their contracts in future customer rates.

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2014.

The table above does not reflect payments related to the manufactured gas plant remediation liability of $613.7 million at December 31, 2011, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 16, *Commitments and Contingencies*, for more information about environmental liabilities. The table also does not reflect payments for the December 31, 2011, liability of $22.4 million related to unrecognized tax benefits, as the amount and timing of payments are uncertain. See Note 15, *Income Taxes*, for more information on unrecognized tax benefits.

Table of Contents

Capital Requirements

As of December 31, 2011, our subsidiaries capital expenditures for the three-year period 2012 through 2014 were expected to be as follows:

(Millions)		
WPS		
Environmental projects	$	**510.7**
Electric and natural gas distribution projects		**201.1**
Electric and natural gas delivery and customer service projects		**63.7**
Other projects		**176.0**
UPPCO		
Repairs and safety measures at hydroelectric facilities		**16.6**
Other projects		**31.7**
MGU		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**34.8**
MERC		
Natural gas pipe distribution system and other projects		**53.2**
PGL		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**699.9**
NSG		
Natural gas pipe distribution system and other projects		**85.2**
Integrys Energy Services		
Solar and other projects		**98.6**
IBS		
Corporate services infrastructure projects		**96.2**
ITF		
Compressed natural gas fueling stations		**71.0**
Total capital expenditures	$	**2,138.7**

We expect to provide capital contributions to INDU Solar Holdings, LLC, (not included in the above table) of approximately $45 million in 2012. INDU Solar Holdings was created in October 2010, through wholly owned subsidiaries of both Integrys Energy Services and Duke Energy Generation Services, to build and finance distributed solar projects throughout the United States.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $15 million from 2012 through 2014.

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

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management policies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage the liquidity and capital resource needs of the business segments. We plan to meet our capital requirements for the period 2012 through 2014 primarily through internally generated funds (net of forecasted dividend payments) and debt and equity financings. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth. We believe we have adequate financial flexibility and resources to meet our future needs.

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

Under an existing shelf registration statement, WPS may issue up to $500.0 million of senior debt securities with amounts, prices, and terms to be determined at the time of future offerings.

Table of Contents

At December 31, 2011, we and each of our subsidiaries were in compliance with all covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 12, *Short-Term Debt and Lines of Credit*, for more information on credit facilities and other short-term credit agreements, including short-term debt covenants. See Note 13, *Long-Term Debt*, for more information on long-term debt and related covenants.

Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. Our regulated utility subsidiaries are prohibited from loaning funds to us, either directly or indirectly. Although these restrictions limit the amount of funding the various operating subsidiaries can provide to us, management does not believe these restrictions will have a significant impact on our ability to access cash for payment of dividends on common stock or other future funding obligations. See Note 20, *Common Equity,* for more information on dividend restrictions.

Other Future Considerations

Decoupling

In certain jurisdictions, decoupling mechanisms have been implemented. These mechanisms differ state by state and allow utilities to adjust future rates to recover or refund all or a portion of the differences between actual and authorized margin.

• Decoupling for residential and small commercial and industrial sales was approved by the ICC on a four-year trial basis for PGL and NSG, effective March 1, 2008. Interveners, including the Illinois Attorney General, oppose decoupling and have appealed the ICC s approval. PGL and NSG actively support the ICC s decision to approve decoupling. In the PGL and NSG rate order approved on January 10, 2012, the ICC made the decoupling mechanism (based on total margin) permanent for both companies. The appeal of the original decoupling order is pending and, depending on the outcome, could impact the current rate order provision for decoupling.

• Decoupling for natural gas and electric residential and small commercial and industrial sales was approved by the PSCW on a four-year trial basis for WPS, effective January 1, 2009, and ending on December 31, 2012. The mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels, nor does it cover all customer classes. This decoupling mechanism includes an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers are subject to these caps and are included in rates upon approval in a rate order. WPS expects to address decoupling beyond 2012 in its rate case filing for 2013.

• Decoupling for UPPCO was approved for the majority of customer classes by the MPSC, effective January 1, 2010, and ended on December 31, 2011. A new weather-normalized decoupling mechanism based on total margin will become effective for UPPCO on January 1, 2013. UPPCO has no decoupling mechanism in place for 2012.

- The MPSC granted an order, effective January 1, 2010, approving a decoupling mechanism for MGU that covers residential and small commercial and industrial customers. The decoupling mechanism does not adjust for weather-related usage, nor does it adjust for variations in volumes resulting from changes in customer count compared to rate case levels. The decoupling mechanism does not cover all customer classes.

- In Minnesota, MERC proposed a decoupling mechanism in its November 30, 2010 general rate case filing. A final order is expected in the second quarter of 2012.

See Note 26, *Regulatory Environment*, for more information.

Climate Change

The EPA began regulating greenhouse gas emissions under the Clean Air Act in January 2011 by applying the Best Available Control Technology (BACT) requirements (associated with the New Source Review program) to new and modified larger greenhouse gas emitters. Technology to remove and sequester greenhouse gas emissions is not commercially available at scale. Therefore, the EPA issued guidance that defines BACT in terms of improvements in energy efficiency as opposed to relying on pollution control equipment. In December 2010, the EPA announced its intent to develop new source performance standards for greenhouse gas emissions. The standards would apply to new and modified, as well as existing, electric utility steam generating units. The EPA planned to propose these standards in 2011 and finalize them in 2012; however, the proposal has since been delayed.

Table of Contents

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

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

Property Tax Assessment on Natural Gas

Our subsidiaries and natural gas retailers purchase storage services from pipeline companies on interstate systems. Some states tax natural gas held as working natural gas in facilities located within their jurisdiction as personal property. Shippers that are being assessed a tax are actively protesting these property tax assessments. MERC is currently pursuing a protest through litigation in Kansas.

Federal Health Care Reform

In March 2010, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (HCR) were signed into law. HCR contains various provisions that will affect the cost of providing health care coverage to our active and retired employees and their dependents. Although these provisions become effective at various times over the next 10 years, some provisions that affect the cost of providing benefits to retirees were reflected in our financial statements in 2010 and 2011.

Beginning in 2013, a provision of HCR will eliminate the tax deduction for employer-paid postretirement prescription drug charges to the extent those charges will be offset by the receipt of a federal Medicare Part D subsidy. As a result, we eliminated $11.8 million of our deferred tax asset related to postretirement benefits in 2010. Of this amount, $10.8 million flowed through to net income as a component of income tax expense in 2010. The remaining $1.0 million was deferred for regulatory recovery at UPPCO. An additional $1.5 million was expensed in June 2011 for deferred income taxes related to a Wisconsin tax law change (see discussion in Recent Tax Law Changes below). In the fourth quarter of 2011, PGL and NSG recorded a regulatory asset of $5.8 million, reversing amounts previously expensed in 2010, as PGL and NSG were authorized recovery of these amounts in the rate order approved on January 10, 2012. In addition, WPS was authorized recovery in February 2012 for the portion related to its Michigan operations that was previously expensed in 2010. We expect to seek rate recovery for the remaining $5.9 million of income tax expense that relates to this tax law change associated with our regulated operations. If recovery in rates becomes probable in the remaining jurisdiction, income tax expense will be reduced in that period. We are not currently able to predict how much of the remaining portion, if any, will be recovered in rates.

Other provisions of HCR include the elimination of certain annual and lifetime maximum benefits and the broadening of plan eligibility requirements. It also includes the elimination of pre-existing condition restrictions, an excise tax on high-cost health plans, changes to the Medicare Part D prescription drug program, and numerous other changes. We participate in the Early Retiree Reinsurance Program that became effective on June 1, 2010. We continue to assess the extent to which the provisions of the new law will affect our future health care and related employee benefit plan costs.

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

The Dodd-Frank Act was signed into law in July 2010. However, significant rulings essential to its framework still remain outstanding. Depending on the final rules, certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. Final rules for these provisions are expected in the second quarter of 2012. We are monitoring developments related to this act and their impacts on our future financial results.

Recent Tax Law Changes

Federal

In December 2010, President Obama signed into law The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This act includes tax incentives, such as an extension and increase of bonus depreciation, the extension of the research and experimentation credit, and the extension of treasury grants in lieu of claiming the investment tax credit or production tax credit for certain renewable energy investments. In September 2010, President Obama signed into law the Small Business Jobs Act of 2010. This act includes tax incentives, such as an extension to bonus depreciation and changes to listed property, that affect us. We anticipate that these tax law changes will likely result in \$140.0 million to \$240.0 million of reduced cash payments for taxes during 2012. These tax incentives may also reduce utility rate base and,

Table of Contents

thus, future earnings relative to prior expectations. We have primarily used the proceeds from these incentives to make incremental contributions to our various employee benefit plans. In addition, these tax incentives have helped reduce our financing needs.

In December 2011, the National Defense Authorization Act (NDAA) was enacted. The most significant provision of the NDAA was to retroactively eliminate the application of the tax normalization rule for cash grants taken by a regulated utility in lieu of the investment tax credit or production tax credits. Prior to the enactment of NDAA, a regulated utility would have been required to amortize the grant in rates over the regulatory life of the renewable energy generating plant. Further, the allowed rate of return on the generating plant could not be reduced by the unamortized grant balance during the life of the plant. As a result of the enactment of NDAA, we are evaluating our options for taking advantage of cash grants in lieu of the production tax credits we are currently claiming for WPS s Crane Creek wind project.

Illinois

In January 2011, Governor Quinn signed into law the Taxpayer Accountability and Budget Stabilization Act. This act increased the corporate combined income tax rate from 7.3% to 9.5% retroactive to January 1, 2011. The rate decreases to 7.75% after 2014 and returns to 7.3% after 2024. We adjusted deferred taxes to reflect the changes in the tax rate in the first quarter of 2011. Due to the effects of regulation, and the timing of the January 10, 2012 rate order for PGL and NSG, we do not expect a material impact on income from this legislation.

Michigan

In May 2011, Governor Snyder signed legislation that replaced Michigan s business tax with a state income tax, effective January 1, 2012. In accounting for this tax law change, we expensed $4.4 million of deferred income taxes in 2011 primarily related to our nonregulated operations and our unitary filings. We deferred an additional $4.2 million in 2011 for recovery in future rates.

Wisconsin

In June 2011, Governor Walker signed into law a two-year budget bill. Under the bill, the Wisconsin tax code was changed to conform to the federal tax code, retroactive to December 2010. In accounting for this tax law change, we expensed an additional $1.5 million of deferred income taxes in 2011 related to the Medicare Part D subsidy. The legislation also contains favorable provisions related to the carryforward of net operating losses prior to 2008.

OFF BALANCE SHEET ARRANGEMENTS

See Note 17, *Guarantees*, for information regarding guarantees.

CRITICAL ACCOUNTING POLICIES

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

Risk Management Activities

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

At December 31, 2011, those derivatives not designated as hedges were primarily commodity contracts used to manage price risk associated with natural gas and electricity purchase and sale activities. Cash flow hedge accounting treatment may be used to protect against changes in interest rates. Fair value hedge accounting may be used when we hold assets, liabilities, or firm commitments and enter into transactions that hedge the risk of changes in commodity prices or interest rates. To the extent that the hedging instrument is fully effective in offsetting the transaction being hedged, there is no impact on net income attributed to common shareholders prior to settlement of the hedge.

We have based our valuations on observable inputs whenever possible. However, at times, the valuation of certain derivative instruments requires the use of internally developed valuation techniques and/or significant unobservable inputs. These valuations require a significant amount of management judgment and are classified as Level 3 measurements. Of the total risk management assets on our balance sheets, \$14.9 million (5.1%) were classified as Level 3 measurements. Of the total risk management liabilities, \$22.8 million (5.5%) were classified as Level 3 measurements. We believe these valuations represent the fair values of these instruments as of the reporting date; however, the actual

Table of Contents

amounts realized upon settlement of these instruments could vary materially from the reported amounts due to movements in market prices and changes in the liquidity of certain markets.

As a component of fair value determinations, we consider counterparty credit risk, our own credit risk, and liquidity risk. The liquidity component of the fair value determination may be especially subjective when limited liquid market information is available. Changes in the underlying assumptions for the credit and liquidity risk components of fair value at December 31, 2011, would have had the following effects:

Change in Risk Components	Effect on Fair Value of Net Risk Management Liabilities at December 31, 2011 (Millions)	
100% increase	$	**5.0 decrease**
50% decrease	$	**2.5 increase**

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

As of July 1, 2011, Integrys Energy Services discontinued the use of cash flow hedge accounting. See Note 2, *Risk Management Activities* for further discussion.

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carry a goodwill balance as of April 1, 2011. No impairment was recorded as a result of these tests. For all of our reporting units, the fair value calculated in step one of the test was greater than the carrying value. The fair value was calculated using an equal weighting of the income approach and the market approach.

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

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

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

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

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

The fair values calculated in the first step of the test for MGU, MERC, PGL, and NSG exceeded the carrying values by approximately 6% to 17%. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, that would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test:

Change in key inputs (in basis points)	**MGU**	**MERC**	**PGL**	**NSG**
Discount rate	75	150	175	450
Terminal year return on equity	(195)	(310)	(487)	(810)
Terminal year growth rate	(100)	(225)	N/A*	N/A*

Table of Contents

---

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

Accrued Unbilled Revenues

We accrue estimated amounts of revenues for services provided or energy delivered but not yet billed to customers. Estimated unbilled revenues are calculated using a variety of judgments and assumptions related to customer class or contracted rates. Significant changes in these judgments and assumptions could have a material impact on our results of operations. At December 31, 2011 and 2010, our unbilled revenues were $282.1 million and $339.1 million, respectively. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns, commodity prices, and customer mix.

Pension and Other Postretirement Benefits

The costs of providing non-contributory defined benefit pension benefits and other postretirement benefits, described in Note 18, *Employee Benefit Plans*, are dependent upon numerous factors resulting from actual plan experience and assumptions regarding future experience.

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

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

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

Actuarial Assumption (Millions, except percentages)	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2011 Pension Cost**
Discount rate	(0.5)	$ 102.0	$ 8.9
Discount rate	0.5	(93.7)	(8.5)
Rate of return on plan assets	(0.5)	N/A	6.1
Rate of return on plan assets	0.5	N/A	(6.1)

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

Actuarial Assumption (Millions, except percentages)	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2011 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 37.3	$ 2.7
Discount rate	0.5	(34.9)	(2.2)
Health care cost trend rate	(1.0)	(60.9)	(8.4)
Health care cost trend rate	1.0	73.7	10.9
Rate of return on plan assets	(0.5)	N/A	1.3
Rate of return on plan assets	0.5	N/A	(1.3)

The discount rates are selected based on hypothetical bond portfolios consisting of non-callable (or callable with make-whole provisions), non-collateralized, high-quality corporate bonds with maturities between 0 and 30 years. The bonds are generally rated Aa with a minimum amount outstanding of $50 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans expected future benefit payments.

We establish our expected return on asset assumption based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return was 8.25% in 2011, and 8.50% in 2010 and 2009. For 2011, 2010, and 2009, the actual rates of return on pension plan assets, net of fees, were 1.5%, 13.0%, and 22.0%, respectively.

Table of Contents

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

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and other postretirement benefits, see Note 18, *Employee Benefit Plans*.

Regulatory Accounting

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

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our electric and natural gas utility segment s operations no longer meet the criteria for application. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2011, would result in a 17.9% decrease in total assets and a 5.7% decrease in total liabilities. The two largest regulatory assets at December 31, 2011, related to unrecognized pension and other postretirement benefit costs and environmental remediation costs. A write-off of the unrecognized pension and other postretirement benefit related regulatory asset at December 31, 2011, would result in a 7.3% decrease in total assets. A write-off of the regulatory asset related to environmental remediation costs at December 31, 2011, would result in a 6.3% decrease in total assets. See Note 8, *Regulatory Assets and Liabilities*, for more information.

Income Tax Provision

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

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

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(p), *Summary of Significant Accounting Policies – Income Taxes*, and Note 15, *Income Taxes,* for a discussion of accounting for income taxes.

IMPACT OF INFLATION

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

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks and Other Significant Risks

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

Commodity Price Risk

Utilities

The electric utilities purchase coal, natural gas, and fuel oil for use in power generation. They also buy power from the MISO market at a price that is often reflective of the underlying cost of natural gas used in power generation. Prudent fuel and purchased power costs and capacity payments are recovered from customers under one-for-one recovery mechanisms by UPPCO, and by the wholesale electric operations and Michigan retail electric operations of WPS. The costs of natural gas used by the natural gas utilities are also generally recovered from customers under one-for-one recovery mechanisms. These recovery mechanisms greatly reduce commodity price risk for the utilities.

WPS s Wisconsin retail electric operations do not have a one-for-one recovery mechanism for price fluctuations. Instead, a fuel window mechanism substantially mitigates this price risk.

To manage commodity price risk for their customers, the regulated utilities enter into contracts of various durations for the purchase and/or sale of natural gas, fuel for electric generation, and electricity. In addition, the electric operations of WPS and UPPCO, and the natural gas operations of WPS, PGL, NSG, and MERC, employ risk management techniques, which include the use of derivative instruments such as swaps, futures, and options.

See Note 1(f), *Summary of Significant Accounting Policies Revenues and Customer Receivables*, for more information.

Integrys Energy Services

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

To measure commodity price risk exposure, Integrys Energy Services employs a number of controls and processes, including a value-at-risk (VaR) analysis of its exposures. Integrys Energy Services VaR calculation is used to quantify exposure to market risk associated with its open commodity positions (primarily natural gas and power positions). The VaR calculation excludes the positions created by owning energy assets and associated coal, sulfur dioxide emission allowances, renewable energy credits, and other ancillary fuels. Additionally, financial transmission rights, certain electric ancillary services, and certain portions of long-dated natural gas storage and transportation contracts are also excluded from the VaR calculation. The capped downside nature of the risks and duration of these positions would result in a VaR that would not be representative of the actual exposure. Therefore, Integrys Energy Services evaluates the exposures for these types of contracts by assessing the maximum potential loss of the positions, which is either the cost of the physical asset or the fixed demand charges for the contract.

VaR is a probabilistic approach to quantifying the exposure to market risk. The VaR amount represents an estimate of the potential change in fair value that could occur from changes in market factors, within a given confidence level, if an instrument or portfolio is held for a specified time period. In addition to VaR, Integrys Energy Services employs other risk measurements including mark-to-market valuations, stress testing, and scenario-based testing. In conjunction with the VaR analysis, these other risk measurements provide the risk management analysis for Integrys Energy Services risk exposure.

VaR is not necessarily indicative of actual results that may occur. VaR has a number of limitations that are important to consider when evaluating the calculation results. Most importantly, VaR does not represent the maximum potential loss of the portfolio. Price movements outside of the relevant confidence levels can and do occur and may result in losses exceeding the reported VaR. Large short-term price moves can be caused by catastrophic weather events or other drivers of short-term supply and demand disruptions. Also, the holding period may not always be an adequate assessment of the timeframe to close out positions. Short-term reductions in market liquidity could cause Integrys Energy Services to hold positions open longer than anticipated, resulting in greater than predicted losses. Additionally, there are other risks not captured by the VaR metric including, but not limited to, the risk of customer and vendor nonperformance and the risks associated with the liquidity in the markets in which Integrys Energy Services transacts. Customer and vendor nonperformance risk could result in bad debt losses, realized and unrealized losses on commodity contracts, or increased supply costs in the event that contractual obligations of counterparties are not met. Market liquidity risk refers to the risk that Integrys Energy Services will not be able to efficiently enter or exit commodity positions.

Table of Contents

Integrys Energy Services VaR is calculated using non-discounted positions with a delta-normal approximation based on a one-day holding period and a 95% confidence level, as well as a ten-day holding period and a 99% confidence level. The delta-normal approximation is based on the assumption that changes in the value of the portfolio over short time periods, such as one day or ten days, are normally distributed. Integrys Energy Services VaR calculation includes financial and physical commodity instruments, such as forwards, futures, swaps, and options, as well as natural gas inventory, natural gas storage, and transportation contracts, to the extent such positions are significant, but excludes the positions mentioned above.

The VaR for Integrys Energy Services portfolio at a 95% confidence level and a one-day holding period is presented in the following table:

(Millions)	**2011**	2010
As of December 31	**$ 0.2**	$ 0.2
Average for 12 months ended December 31	**0.2**	0.3
High for 12 months ended December 31	**0.3**	0.3
Low for 12 months ended December 31	**0.1**	0.2

The VaR for Integrys Energy Services portfolio at a 99% confidence level and a ten-day holding period is presented in the following table:

(Millions)	**2011**	2010
As of December 31	**$ 0.7**	$ 1.1
Average for 12 months ended December 31	**0.7**	1.4
High for 12 months ended December 31	**1.2**	1.5
Low for 12 months ended December 31	**0.5**	1.1

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

The year-over-year decrease in VaR was driven primarily by reduced business size, as a result of Integrys Energy Services strategy change.

Interest Rate Risk

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

Due to short-term borrowings, we are exposed to variable interest rates. Based on our variable rate debt outstanding at December 31, 2011, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $3.3 million. Comparatively, based on the variable rate debt outstanding at December 31, 2010, an increase in interest rates of 100 basis points would have increased annual interest expense by $1.4 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Equity Return and Principal Preservation Risk

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

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on this assessment, management believes that, as of December 31, 2011, our internal control over financial reporting is effective.

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

Table of Contents

B. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Integrys Energy Group, Inc.:

We have audited the internal control over financial reporting of Integrys Energy Group, Inc. and subsidiaries (the Company) as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Milwaukee, Wisconsin

February 28, 2012

Table of Contents

C. CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 (Millions, except per share data)	2011	2010	2009
Utility revenues	**$ 3,294.5**	$ 3,368.5	$ 3,495.8
Nonregulated revenues	**1,414.2**	1,834.7	4,004.0
Total revenues	**4,708.7**	5,203.2	7,499.8
Utility cost of fuel, natural gas, and purchased power	**1,635.3**	1,685.5	1,919.8
Nonregulated cost of sales	**1,281.6**	1,619.8	3,701.3
Operating and maintenance expense	**1,028.2**	1,045.6	1,098.4
Impairment losses on property, plant, and equipment	**4.6**	43.2	0.7
Restructuring expense	**2.0**	7.9	43.5
Net (gain) loss on Integrys Energy Services dispositions related to strategy change	**(0.3)**	14.1	28.9
Goodwill impairment loss			291.1
Depreciation and amortization expense	**250.1**	265.8	230.6
Taxes other than income taxes	**98.4**	93.2	96.3
Operating income	**408.8**	428.1	89.2
Miscellaneous income	**84.8**	91.5	89.0
Interest expense	**(128.8)**	(147.9)	(164.8)
Other expense	**(44.0)**	(56.4)	(75.8)
Income before taxes	**364.8**	371.7	13.4
Provision for income taxes	**133.9**	148.2	83.7
Net income (loss) from continuing operations	**230.9**	223.5	(70.3)
Discontinued operations, net of tax	**(0.4)**	0.2	2.8
Net income (loss)	**230.5**	223.7	(67.5)
Preferred stock dividends of subsidiary	**(3.1)**	(3.1)	(3.1)
Noncontrolling interest in subsidiaries		0.3	1.0
Net income (loss) attributed to common shareholders	**$ 227.4**	$ 220.9	$ (69.6)
Average shares of common stock			
Basic	**78.6**	77.5	76.8
Diluted	**79.1**	78.0	76.8
Earnings (loss) per common share (basic)			
Net income (loss) from continuing operations	**$ 2.90**	$ 2.85	$ (0.95)
Discontinued operations, net of tax	**(0.01)**		0.04
Earnings (loss) per common share (basic)	**$ 2.89**	$ 2.85	$ (0.91)
Earnings (loss) per common share (diluted)			
Net income (loss) from continuing operations	**$ 2.88**	$ 2.83	$ (0.95)
Discontinued operations, net of tax	**(0.01)**		0.04
Earnings (loss) per common share (diluted)	**$ 2.87**	$ 2.83	$ (0.91)
Dividends per common share declared	**$ 2.72**	$ 2.72	$ 2.72

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

Table of Contents

D. CONSOLIDATED BALANCE SHEETS

At December 31 (Millions)	2011	2010
Assets		
Cash and cash equivalents	**$ 28.1**	$ 179.0
Collateral on deposit	**50.9**	33.3
Accounts receivable and accrued unbilled revenues, net of reserves of $47.1 and $41.9, respectively	**737.7**	832.1
Inventories	**252.3**	247.9
Assets from risk management activities	**227.2**	236.9
Regulatory assets	**125.1**	117.9
Deferred income taxes	**94.2**	67.7
Prepaid taxes	**209.6**	269.9
Other current assets	**78.2**	65.7
Current assets	**1,803.3**	2,050.4
Property, plant, and equipment, net of accumulated depreciation of $3,018.7 and $2,900.2, respectively	**5,199.1**	5,013.4
Regulatory assets	**1,658.5**	1,495.1
Assets from risk management activities	**64.4**	89.4
Goodwill	**658.4**	642.5
Other long-term assets	**599.5**	526.0
Total assets	**$ 9,983.2**	$ 9,816.8
Liabilities and Equity		
Short-term debt	**$ 303.3**	$ 10.0
Current portion of long-term debt	**250.0**	476.9
Accounts payable	**426.6**	453.0
Liabilities from risk management activities	**311.6**	289.6
Accrued taxes	**70.5**	90.2
Regulatory liabilities	**67.5**	75.7
Other current liabilities	**217.2**	262.4
Current liabilities	**1,646.7**	1,657.8
Long-term debt	**1,872.0**	2,161.6
Deferred income taxes	**1,070.7**	860.5
Deferred investment tax credits	**44.0**	45.2
Regulatory liabilities	**332.5**	316.2
Environmental remediation liabilities	**615.1**	643.9
Pension and other postretirement benefit obligations	**749.3**	603.4
Liabilities from risk management activities	**102.0**	99.7
Asset retirement obligations	**397.2**	320.9
Other long-term liabilities	**141.1**	150.6
Long-term liabilities	**5,323.9**	5,202.0
Commitments and contingencies		
Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,904,935 shares outstanding	**78.3**	77.8
Additional paid-in capital	**2,579.1**	2,540.4
Retained earnings	**363.6**	350.8
Accumulated other comprehensive loss	**(42.5)**	(44.7)

Shares in deferred compensation trust		**(17.1)**		(18.5)
Total common shareholders equity		**2,961.4**		2,905.8
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		**51.1**		51.1
Noncontrolling interest in subsidiaries		**0.1**		0.1
Total liabilities and equity	**$**	**9,983.2**	$	9,816.8

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

Table of Contents

E. CONSOLIDATED STATEMENTS OF EQUITY

	Integrys Energy Group Common Shareholders Equity								
(Millions)	Deferred Compensation Trust and Treasury Stock	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders Equity	Preferred Stock of Subsidiary	Noncontrolling Interest	Total Equity
Balance at December 31, 2008	$ (16.5)	$ 76.4	$ 2,487.9	$ 614.7	$ (72.8)	$ 3,089.7	$ 51.1	$	$ 3,140.8
Net loss attributed to common shareholders				(69.6)		(69.6)		(1.0)	(70.6)
Other comprehensive income (loss)									
Cash flow hedges (net of tax of $17.0)					31.5	31.5			31.5
Unrecognized pension and other postretirement costs (net of tax of $3.2)					(6.7)	(6.7)			(6.7)
Available-for-sale securities (net of tax of $0.1)					(0.1)	(0.1)			(0.1)
Foreign currency translation (net of tax of $2.6)					4.1	4.1			4.1
Comprehensive loss						(40.8)			(41.8)
Purchase of deferred compensation shares	(3.1)					(3.1)			(3.1)
Stock based compensation	0.1		11.3			11.4			11.4
Dividends on common stock				(206.9)		(206.9)			(206.9)
Net contributions from noncontrolling parties								0.1	0.1
Other	2.3		(1.4)	(1.2)		(0.3)			(0.3)
Balance at December 31, 2009	$ (17.2)	$ 76.4	$ 2,497.8	$ 337.0	$ (44.0)	$ 2,850.0	$ 51.1	$ (0.9)	$ 2,900.2
Net income attributed to common shareholders				220.9		220.9		(0.3)	220.6
Other comprehensive income (loss)									
Cash flow hedges (net of tax of $4.7)					4.5	4.5			4.5
Unrecognized pension and other postretirement costs (net of tax of $2.0)					(2.8)	(2.8)			(2.8)
Foreign currency translation (net of tax of $1.5)					(2.4)	(2.4)			(2.4)
Comprehensive income						220.2			219.9
Issuance of common stock		1.3	54.5			55.8			55.8
Purchase of deferred compensation shares	(1.2)					(1.2)			(1.2)
Stock based compensation			4.0			4.0			4.0
Dividends on common stock				(208.7)		(208.7)			(208.7)
Other	(0.1)	0.1	(15.9)	1.6		(14.3)		1.3	(13.0)
Balance at December 31, 2010	$ (18.5)	$ 77.8	$ 2,540.4	$ 350.8	$ (44.7)	$ 2,905.8	$ 51.1	$ 0.1	$ 2,957.0
Net income attributed to common shareholders				**227.4**		**227.4**		**0.0**	**227.4**
Other comprehensive income (loss)									
Cash flow hedges (net of tax of $4.8)					**8.9**	**8.9**			**8.9**

Unrecognized pension and other postretirement costs (net of tax of $5.1)					**(6.7)**	**(6.7)**			**(6.7)**
Comprehensive income						**229.6**			**229.6**
Issuance of common stock		**0.5**	**21.7**			**22.2**			**22.2**
Purchase of deferred compensation shares	**(1.0)**					**(1.0)**			**(1.0)**
Stock based compensation			**7.5**	**(2.1)**		**5.4**			**5.4**
Dividends on common stock				**(211.8)**		**(211.8)**			**(211.8)**
Other	**2.4**		**9.5**	**(0.7)**		**11.2**			**11.2**
Balance at December 31, 2011	**$ (17.1)**	**$ 78.3**	**$ 2,579.1**	**$ 363.6**	**$ (42.5)**	**$ 2,961.4**	**$ 51.1**	**$ 0.1**	**$ 3,012.6**

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

Table of Contents

F. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (Millions)	2011	2010	2009
Operating Activities			
Net income (loss)	**$ 230.5**	$ 223.7	$ (67.5)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Discontinued operations, net of tax	**0.4**	(0.2)	(2.8)
Goodwill impairment loss			291.1
Impairment losses on property, plant, and equipment	**4.6**	43.2	0.7
Depreciation and amortization expense	**250.1**	265.8	230.6
Recoveries and refunds of regulatory assets and liabilities	**56.1**	28.7	40.8
Net unrealized (gains) losses on nonregulated energy contracts	**48.5**	(55.8)	104.2
Nonregulated lower of cost or market inventory adjustments	**11.6**	0.9	44.2
Bad debt expense	**35.0**	48.0	54.6
Pension and other postretirement expense	**60.0**	67.6	72.4
Pension and other postretirement contributions	**(131.5)**	(201.8)	(53.3)
Deferred income taxes and investment tax credits	**175.3**	234.1	58.3
(Gain) loss on sale of assets	**(2.2)**	11.4	24.1
Equity income, net of dividends	**(14.8)**	(14.5)	(16.1)
Other	**32.5**	33.3	37.7
Changes in working capital			
Collateral on deposit	**(17.3)**	163.6	45.5
Accounts receivable and accrued unbilled revenues	**94.1**	97.6	864.8
Inventories	**(28.0)**	51.1	444.1
Other current assets	**46.2**	(85.5)	39.6
Accounts payable	**(37.4)**	(25.8)	(604.7)
Other current liabilities	**(91.8)**	(160.2)	(2.0)
Net cash provided by operating activities	**721.9**	725.2	1,606.3
Investing Activities			
Capital expenditures	**(311.4)**	(258.8)	(444.2)
Proceeds from the sale or disposal of assets	**7.6**	66.0	44.6
Capital contributions to equity method investments	**(37.6)**	(6.9)	(34.1)
Acquisition of compressed natural gas fueling companies, net of cash acquired	**(42.6)**		
Other	**(10.8)**		(7.0)
Net cash used for investing activities	**(394.8)**	(199.7)	(440.7)
Financing Activities			
Short-term debt, net	**303.3**	(212.1)	(815.7)
Redemption of notes payable	**(10.0)**		(157.9)
Proceeds from sale of borrowed natural gas		21.9	162.0
Purchase of natural gas to repay natural gas loans		(6.5)	(445.2)
Issuance of long-term debt	**50.0**	250.0	230.0
Repayment of long-term debt	**(565.8)**	(117.2)	(157.8)
Payment of dividends			
Preferred stock of subsidiary	**(3.1)**	(3.1)	(3.1)
Common stock	**(206.4)**	(186.1)	(206.9)
Issuance of common stock	**4.9**	33.2	
Proceeds from derivative contracts related to divestitures classified as financing activities			33.9
	(31.9)	(157.8)	

Payments made on derivative contracts related to divestitures classified as financing activities						
Other		**(19.4)**		(13.7)		(17.7)
Net cash used for financing activities		**(478.4)**		(391.4)		(1,378.4)
Change in cash and cash equivalents - continuing operations		**(151.3)**		134.1		(212.8)
Change in cash and cash equivalents - discontinued operations						
Net cash provided by investing activities		**0.4**		0.4		3.2
Net change in cash and cash equivalents		**(150.9)**		134.5		(209.6)
Cash and cash equivalents at beginning of year		**179.0**		44.5		254.1
Cash and cash equivalents at end of year	**$**	**28.1**	$	179.0	$	44.5

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

Table of Contents

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations We are a holding company whose primary wholly owned subsidiaries at December 31, 2011, included WPS, UPPCO, MGU, MERC, PGL, NSG, IBS, Integrys Energy Services, and ITF. Of these subsidiaries, six are regulated electric and/or natural gas utilities, one, IBS, is a centralized service company, one, Integrys Energy Services, is a nonregulated retail energy supply and services company, and one, ITF, is a nonregulated compressed natural gas fueling business. In addition, we have an approximate 34% interest in ATC.

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

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

(b) Consolidated Basis of Presentation The financial statements include our accounts and the accounts of all of our majority owned subsidiaries, after eliminating intercompany transactions and balances. These financial statements also reflect our proportionate interests in certain jointly owned utility facilities. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. Investments in businesses not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. For more information on equity method investments, see Note 9, *Investments in Affiliates, at Equity Method.*

(c) Reclassifications We reclassified $127.2 million reported in other current assets at December 31, 2010, to prepaid taxes to match the current year presentation on the balance sheet.

(d) Use of Estimates We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. We make estimates and assumptions that affect assets, liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(e) Cash and Cash Equivalents Short-term investments with an original maturity of three months or less are reported as cash equivalents.

The following is supplemental disclosure to our statements of cash flows:

(Millions)	2011	2010	2009
Cash paid for interest	**$ 130.7**	$ 138.7	$ 164.8
Cash (received) paid for income taxes	**(80.0)**	(2.2)	19.1

Significant noncash transactions were:

(Millions)	2011	2010	2009
Construction costs funded through accounts payable	**$ 58.6**	$ 18.3	$ 30.4
Equity issued for stock-based compensation plans	**15.8**	3.0	
Equity issued for reinvested dividends	**5.4**	22.6	
Intangible assets (customer contracts) received in exchange for risk management assets			17.0

(f) Revenues and Customer Receivables Revenues related to the sale of energy are recognized when service is provided or energy is delivered to customers and include estimated amounts for services provided but not billed. At December 31, 2011 and 2010, our unbilled revenues were $282.1 million and $339.1 million, respectively. At December 31, 2011, there were no customers or industries that accounted for more than 10% of our revenues. We present revenue net of pass-through taxes on the income statements.

Our utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of prudently incurred electric fuel costs, purchased power costs, and natural gas costs, which allow subsequent adjustments to rates for changes in commodity costs. Other mechanisms also allow recovery for environmental costs, conservation improvement program (CIP) costs, bad debts, and energy conservation and management programs. A summary of significant rate-adjustment mechanisms follows:

Table of Contents

- Fuel and purchased power costs are recovered from customers on a one-for-one basis by UPPCO, WPS s wholesale electric operations, and WPS s Michigan retail electric operations.

- WPS s Wisconsin retail electric operations use a fuel window mechanism to recover fuel and purchased power costs. Under the fuel window rules effective January 1, 2011, a deferral is required for under or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers. Under or over-collections deferred in the current year are recovered or refunded in a future rate proceeding.

- The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs.

- The rates of PGL and NSG include riders for cost recovery of both environmental cleanup and energy conservation and management program costs.

- MERC s rates include a CIP rider for cost recovery of energy conservation and management program costs as well as recovery of a financial incentive for meeting energy savings goals.

- The rates of PGL, NSG, and MGU include riders for cost recovery or refund of bad debts based on the difference between actual bad debt cost (as defined in the latest rate order) and the amount recovered in rates.

- Decoupling mechanisms were in place at WPS, PGL, NSG, MGU, and UPPCO for 2011. These mechanisms differ state by state and allow utilities to adjust rates going forward to recover or refund all or a portion of the differences between actual and authorized margins.

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

ITF accounts for revenues from construction management projects with the percentage of completion method. Revenue is measured by the percentage of costs incurred to date to the estimated total costs for each contract. This method is used because management considers total costs to be the best available measure of progress on these contracts.

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

(g) Inventories Inventories consist of natural gas in storage, liquid propane, and fossil fuels, including coal. Average cost is used to value fossil fuels, liquid propane, and natural gas in storage for the regulated utilities, excluding PGL and NSG. PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 37% of total inventories at December 31, 2011, and 34% of total inventories at December 31, 2010. The estimated replacement cost of natural gas in inventory at December 31, 2011, and December 31, 2010, exceeded the LIFO cost by approximately $65.7 million and $136.7 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per dekatherm of $3.06 at December 31, 2011, and $4.42 at December 31, 2010.

Inventories at Integrys Energy Services are valued at the lower of cost or market. Integrys Energy Services recorded net write-downs of $11.6 million, $0.9 million, and $44.2 million in 2011, 2010, and 2009, respectively.

(h) Risk Management Activities As part of our regular operations, we enter into contracts, including options, swaps, futures, forwards, and other contractual commitments, to manage market risks such as changes in commodity prices and interest rates, which are described more fully in Note 2, *Risk Management Activities*. Derivative instruments at the utilities are entered into in accordance with the terms of the risk management plans approved by their respective Boards of Directors and, if applicable, by their respective regulators.

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

We classify unrealized gains and losses on derivative instruments that do not qualify for hedge accounting or regulatory deferral as a component of margins or operating and maintenance expense, depending on the nature of the transactions. Unrealized gains and losses on fair value hedges are recognized in current earnings, as are the changes in fair value of the hedged items. To the extent they are effective, the changes in the values of contracts designated as cash flow hedges are included in other comprehensive income, net of taxes. Fair value hedge ineffectiveness and cash flow hedge ineffectiveness are recorded in revenue, operating and maintenance expense, or interest expense on the statements of income, based on the nature of the transactions. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on the statements of cash flows unless the derivative contracts contain an other-than-insignificant financing element, in which case the cash flows are classified within financing activities.

Table of Contents

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

We have risk management contracts with various counterparties. We monitor credit exposure levels and the financial condition of our counterparties on a continuous basis to minimize credit risk. At December 31, 2011, we did not have risk management contracts with any one counterparty or industry that accounted for more than 10% of our total credit risk exposure.

(i) Emission Allowances Integrys Energy Services accounts for emission allowances as intangible assets, with cash inflows and outflows related to purchases and sales of emission allowances recorded as investing activities in the Statements of Cash Flows. The utilities account for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating the utilities generation plants. Gains on sales of allowances at the utilities are returned to ratepayers. Losses on emission allowances at the utilities are included in the costs subject to the fuel window rules.

(j) Property, Plant, and Equipment Utility plant is stated at original cost, including any associated AFUDC and asset retirement costs. The costs of renewals and betterments of units of property (as distinguished from minor items of property) are capitalized as additions to the utility plant accounts. Except for land, no gains or losses are recognized in connection with ordinary retirements of utility property units. The utilities charge the cost of units of property retired, sold, or otherwise disposed of, less salvage value, to accumulated depreciation. In addition, the utilities record a regulatory liability for cost of removal accruals, which are included in rates. Actual removal costs are charged against the regulatory liability as incurred. Maintenance, repair, replacement, and renewal costs associated with items not qualifying as units of property are considered operating expenses. We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates as approved by the applicable regulators. Annual utility composite depreciation rates are shown below. WPS received approval from the PSCW for lower depreciation rates, effective January 1, 2011.

Annual Utility Composite Depreciation Rates	2011	2010	2009
WPS Electric	**2.88%**	3.05%	3.04%
WPS Natural gas	**2.22%**	3.28%	3.30%
UPPCO	**3.33%**	3.18%	3.05%
MGU	**2.73%**	3.55%	2.66%
MERC	**3.10%**	3.08%	3.10%
PGL	**3.18%**	3.10%	2.29%
NSG	**2.42%**	2.35%	1.66%

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

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

See Note 6, *Property, Plant, and Equipment*, for details regarding our property, plant, and equipment balances.

(k) Capitalized Interest and AFUDC Our nonregulated subsidiaries capitalize interest for construction projects; however, interest capitalized was not significant during 2011, 2010, and 2009. Our utilities capitalize the cost of funds used for construction using a calculation that includes both internal equity and external debt components, as required by regulatory accounting. The internal equity component of capitalized AFUDC is accounted for as other income, and the external debt component is accounted for as a decrease to interest expense.

Approximately 50% of WPS s retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. For 2011, WPS s average AFUDC retail rate was 7.71%, and its average AFUDC wholesale rate was 4.16%. WPS s allowance for equity funds used during construction for 2011, 2010, and 2009 was \$0.6 million, \$0.7 million, and \$5.1 million, respectively. WPS s allowance for borrowed funds used during construction for 2011, 2010, and 2009 was \$0.2 million, \$0.3 million, and \$2.0 million, respectively.

The AFUDC calculation for the other utilities and IBS is determined by the respective state commissions, each with specific requirements. Based on these requirements, the other utilities and IBS did not record significant AFUDC for 2011, 2010, or 2009.

Table of Contents

(l) Regulatory Assets and Liabilities Regulatory assets represent probable future revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in rates for future costs. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the year the determination is made. See Note 8, *Regulatory Assets and Liabilities*, for more information.

(m) Asset Impairment Goodwill and other intangible assets with indefinite lives are not amortized, but are subject to an annual impairment test. Other long-lived assets require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements, and other external market conditions or factors. See Note 6, *Property, Plant, and Equipment*, for a discussion of recent impairments related to other long-lived assets.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year, and interim impairment tests when impairment indicators are present. The carrying amount of the reporting unit s goodwill is considered not recoverable if it exceeds the reporting unit s fair value. An impairment loss is recorded for the excess of the carrying value of the goodwill over its implied fair value. For more information on our goodwill and other intangible assets, see Note 10, *Goodwill and Other Intangible Assets*.

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

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

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

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

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

(o) Asset Retirement Obligations We recognize legal obligations at fair value associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development, and/or normal operation of the assets. A liability is recorded for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The asset retirement obligations are accreted using a credit-adjusted risk-free interest rate commensurate with the expected settlement dates of the asset retirement obligations; this rate is determined at the date the obligation is incurred. The associated retirement costs are capitalized as part of the related long-lived assets and are depreciated over the useful lives of the assets. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the liability and the associated retirement cost. See Note 14, *Asset Retirement Obligations*, for more information.

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

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. We record valuation allowances for deferred income tax assets when it is uncertain if the benefit will be realized in the future. Our regulated utilities defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

Table of Contents

We use the deferral method of accounting for investment tax credits (ITCs). Under this method, we record the ITCs as deferred credits and amortize such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. Production tax credits generally reduce the provision for income taxes in the year that electricity from the qualifying facility is generated and sold. Investment tax credits and production tax credits that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset. A valuation allowance is established unless it is more likely than not that the credits will be realized during the carryforward period.

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

For more information regarding accounting for income taxes, see Note 15, *Income Taxes*.

(q) Guarantees Integrys Energy Group follows the guidance of the Guarantees Topic of the FASB ASC, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. For additional information on guarantees, see Note 17, *Guarantees*.

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

We recognize the funded status of defined benefit postretirement plans on the balance sheet, and recognize changes in the plans funded status in the year in which the changes occur. Our nonregulated segments record changes in the funded status in other comprehensive income, and the regulated utilities record these changes in regulatory asset or liability accounts.

For additional information on our employee benefits, see Note 18, *Employee Benefit Plans*.

(s) Fair Value A fair value measurement is required to reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the model. Transaction costs should not be considered in the determination of fair value.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities.

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methodologies.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers needs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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

Table of Contents

When possible, we base the valuations of our risk management assets and liabilities on quoted prices for identical assets in active markets. These valuations are classified in Level 1. The valuations of certain contracts include inputs related to market price risk (commodity or interest rate), price volatility (for option contracts), price correlation (for cross commodity contracts), credit risk, and time value. These inputs are available through multiple sources, including brokers and over-the-counter and online exchanges. Transactions valued using these inputs are classified in Level 2.

Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. The primary reasons for a Level 3 classification are as follows:

- While price curves may have been based on observable information, significant assumptions may have been made regarding seasonal or monthly shaping and locational basis differentials.
- Certain transactions were valued using price curves that extended beyond the quoted period. Assumptions were made to extrapolate prices from the last quoted period through the end of the transaction term, primarily through the use of historically settled data or correlations to other locations.

We recognize transfers between the levels of the fair value hierarchy at the value as of the end of the reporting period.

See Note 23, *Fair Value*, for additional information.

(t) New Accounting Pronouncements ASU 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS), was issued in May 2011. The amendments change the wording used to describe the requirements for measuring fair value and for disclosing information about fair value measurements. The amendments also clarify the intent concerning the application of existing fair value measurement requirements. This guidance is effective for our reporting period ending March 31, 2012. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

ASU 2011-05, Presentation of Comprehensive Income, was issued in June 2011. The guidance requires that the total of comprehensive income, the components of net income, and the components of OCI be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The FASB has deferred the requirement regarding the presentation of reclassification adjustments between OCI and net income on the face of the financial statements. This guidance is effective for our reporting period ending March 31, 2012, and is expected to change the format of our financial statements.

ASU 2011-08, Testing Goodwill for Impairment, was issued in September 2011. The amendments give companies an option to first perform a qualitative assessment to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If a company concludes that this is the case, the quantitative impairment test is required. Otherwise, a company can bypass the quantitative impairment test. This guidance is effective for our reporting period ending March 31, 2012, and is not expected to have a significant impact on our financial statements.

ASU 2011-11, Disclosures about Offsetting Assets and Liabilities, was issued in December 2011. The guidance requires enhanced disclosures about offsetting and related arrangements. This guidance is effective for our reporting period ending March 31, 2013. Management is currently evaluating the impact that the adoption of this standard will have on our financial statements.

Table of Contents

NOTE 2 RISK MANAGEMENT ACTIVITIES

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

		December 31, 2011	
(Millions)	**Balance Sheet Presentation ***	**Assets from Risk Management Activities**	**Liabilities from Risk Management Activities**
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 9.1	$ 35.4
Natural gas contracts	Long-term	0.1	8.2
Financial transmission rights (FTRs)	Current	2.3	0.1
Petroleum product contracts	Current	0.1	
Coal contract	Current		2.5
Coal contract	Long-term		4.4
Cash flow hedges			
Natural gas contracts	Current		0.9
Natural gas contracts	Long-term		0.2
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	121.6	120.5
Natural gas contracts	Long-term	41.9	40.5
Electric contracts	Current	93.9	152.0
Electric contracts	Long-term	22.4	48.7
Foreign exchange contracts	Current	0.2	0.2
	Current	227.2	311.6
	Long-term	64.4	102.0
Total		$ 291.6	$ 413.6

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based on the maturities of the underlying contracts.

Table of Contents

(Millions)	Balance Sheet Presentation *	December 31, 2010 Assets from Risk Management Activities	Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	$ 2.2	$ 23.6
Natural gas contracts	Long-term	1.6	1.4
FTRs	Current	3.1	0.2
Petroleum product contracts	Current	0.6	
Coal contract	Current		1.2
Coal contract	Long-term	3.7	
Cash flow hedges			
Natural gas contracts	Current		1.0
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	132.0	113.8
Natural gas contracts	Long-term	62.3	57.7
Electric contracts	Current	85.7	122.0
Electric contracts	Long-term	16.5	30.3
Foreign exchange contracts	Current	1.2	1.2
Foreign exchange contracts	Long-term	0.3	0.3
Fair value hedges			
Interest rate swaps	Current	0.9	
Cash flow hedges			
Natural gas contracts	Current	1.6	9.2
Natural gas contracts	Long-term	0.1	0.9
Electric contracts	Current	9.6	17.4
Electric contracts	Long-term	4.9	9.1
	Current	236.9	289.6
	Long-term	89.4	99.7
Total		$ 326.3	$ 389.3

* All derivatives are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and sales exception. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. We classify assets and liabilities from risk management activities as current or long-term based on the maturities of the underlying contracts.

The following table shows our cash collateral positions:

(Millions)	December 31, 2011	December 31, 2010
Cash collateral provided to others	**$ 50.9**	$ 33.3
Cash collateral received from others *	**2.3**	4.5

* Reflected in other current liabilities on the Balance Sheets.

Certain of our derivative and nonderivative commodity instruments contain provisions that could require adequate assurance in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The following table shows the aggregate fair value of all derivative instruments with specific credit risk related contingent features that were in a liability position:

(Millions)	**December 31, 2011**	**December 31, 2010**
Integrys Energy Services	**$ 193.8**	$ 219.5
Utility segments	**39.1**	22.1

Table of Contents

If all of the credit risk related contingent features contained in commodity instruments (including derivatives, nonderivatives, normal purchase and normal sales contracts, and applicable payables and receivables) had been triggered, our collateral requirement would have been as follows:

(Millions)		December 31, 2011	December 31, 2010
Collateral that would have been required:			
Integrys Energy Services		**$ 272.3**	$ 295.7
Utility segments		**28.7**	14.1
Collateral already satisfied:			
Integrys Energy Services	Letters of credit	**11.0**	56.9
Collateral remaining:			
Integrys Energy Services		**261.3**	238.8
Utility segments		**28.7**	14.1

Utility Segments

Non-Hedge Derivatives

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

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

	December 31, 2011		December 31, 2010	
	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**1,122.7**	**N/A**	979.9	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**5,077.5**	N/A	5,882.5
Petroleum products (barrels)	**46,872.0**	**N/A**	71,827.0	N/A
Coal contract (millions of tons)	**4.1**	**N/A**	4.9	N/A

The tables below show the unrealized gains (losses) recorded related to non-hedge derivatives at the utilities:

(Millions)	Financial Statement Presentation		2011	2010
Natural gas contracts	Balance Sheet	Regulatory assets (current)	**$ (11.3)**	$ (1.7)
Natural gas contracts	Balance Sheet	Regulatory assets (long-term)	**(7.6)**	0.1
Natural gas contracts	Balance Sheet	Regulatory liabilities (current)	**8.4**	
FTRs	Balance Sheet	Regulatory assets (current)	**(0.4)**	1.0
FTRs	Balance Sheet	Regulatory liabilities (current)	**(1.3)**	(2.1)

Petroleum product contracts	Balance Sheet	Regulatory assets (current)	**(0.1)**	
Petroleum product contracts	Balance Sheet	Regulatory liabilities (current)		0.1
Petroleum product contracts	Income Statement	Operating and maintenance expense	**(0.1)**	0.1
Coal contract	Balance Sheet	Regulatory assets (current)	**(1.3)**	(1.2)
Coal contract	Balance Sheet	Regulatory assets (long-term)	**(4.4)**	
Coal contract	Balance Sheet	Regulatory liabilities (long-term)	**(3.7)**	3.7

(Millions)	**Financial Statement Presentation**			**2009**
Commodity contracts	Balance Sheet	Regulatory assets (current)	$	122.5
Commodity contracts	Balance Sheet	Regulatory assets (long-term)		7.3
Commodity contracts	Balance Sheet	Regulatory liabilities (current)		(1.0)
Commodity contracts	Income Statement	Utility cost of fuel, natural gas, and purchased power		0.1

Cash Flow Hedges

PGL uses natural gas contracts designated as cash flow hedges to hedge changes in the price of natural gas used to support operations. The cost of natural gas used to support operations is not a component of the natural gas costs recovered from customers on a one-for-one basis. These contracts extend through July 2013. PGL had the following notional volumes of outstanding contracts that were designated as cash flow hedges:

	Purchases	
	December 31, 2011	**December 31, 2010**
Natural gas (millions of therms)	**8.1**	5.4

Table of Contents

Changes in the fair values of the effective portions of these contracts are included in OCI, net of taxes. Amounts recorded in OCI related to these cash flow hedges will be recognized in earnings when the hedged transactions occur, or if it is probable that the hedged transaction will not occur. The tables below show the amounts related to cash flow hedges recorded in OCI and in earnings:

Unrealized Loss Recognized in OCI on Derivative Instruments (Effective Portion)

(Millions)	2011	2010	2009
Natural gas contracts	**$ (1.3)**	$ (1.6)	$ (1.4)

Loss Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	Income Statement Presentation	2011	2010	2009
Settled natural gas contracts	Operating and maintenance expense	**$ (1.2)**	$ (0.9)	$ (2.6)

No amounts were reclassified from accumulated OCI into earnings as a result of the discontinuance of cash flow hedge accounting related to these natural gas contracts during 2011, 2010, and 2009. Cash flow hedge ineffectiveness related to these natural gas contracts also was not significant during 2011, 2010, and 2009. When testing for effectiveness, no portion of these derivative instruments was excluded. In the next 12 months, an insignificant loss is expected to be recognized in earnings as the hedged transactions occur.

Nonregulated Segments

Non-Hedge Derivatives

Integrys Energy Services enters into derivative contracts such as futures, forwards, options, and swaps that are not designated as accounting hedges under GAAP. These contracts are used to manage commodity price risk primarily associated with customer-related contracts.

As of July 1, 2011, Integrys Energy Services discontinued the use of cash flow hedge accounting. At December 31, 2011, the amount deferred in accumulated OCI related to cash flow hedges at Integrys Energy Services was a pre-tax loss of $9.9 million. This amount relates to natural gas futures, forwards, and swaps that extend through April 2014, and electric futures, forwards, and swaps that extend through May 2017. This amount will be recognized in earnings as the forecasted transactions occur, or if it becomes probable that the forecasted transactions will not occur.

In the next 12 months, pre-tax losses of $2.0 million and $4.3 million related to the discontinued cash flow hedges of natural gas contracts and electric contracts, respectively, are expected to be recognized in earnings as the forecasted transactions occur. These amounts are expected to be offset by the settlement of the related nonderivative contracts.

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

	December 31, 2011		December 31, 2010	
(Millions)	**Purchases**	**Sales**	**Purchases**	**Sales**
Commodity contracts				
Natural gas (therms)	**959.2**	**797.1**	940.6	1,048.4
Electric (kilowatt-hours)	**34,405.7**	**20,374.0**	22,149.4	19,707.0
Foreign exchange contracts (Canadian dollars)	**4.2**	**4.2**	15.5	15.5

Table of Contents

Gains (losses) related to non-hedge derivatives are recognized currently in earnings, as shown in the tables below:

(Millions)	Income Statement Presentation		2011		2010
Natural gas contracts	Nonregulated revenue	**$**	**14.0**	$	30.9
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI)		**(2.3)***		(1.6)*
Electric contracts	Nonregulated revenue		**(79.0)**		(92.7)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI)		**(1.7)***		(3.7)*
Interest rate swaps	Interest expense				0.4
Total		**$**	**(69.0)**	$	(66.7)

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated in the current and/or prior periods.

(Millions)	Income Statement Presentation		2009
Commodity contracts	Nonregulated revenue	$	(5.1)
Commodity contracts	Nonregulated revenue (reclassified from accumulated OCI)		(3.2)*
Interest rate swaps	Interest expense		(1.7)
Foreign exchange contracts	Nonregulated revenue		(1.8)
Total		$	(11.8)

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated and retained in accumulated OCI in the current and/or prior periods.

Fair Value Hedges

At PELLC, an interest rate swap designated as a fair value hedge was used to hedge changes in the fair value of $50.0 million of the $325.0 million Series A 6.9% notes. The interest rate swap and the notes were settled in January 2011. The changes in the fair value of this hedge were recognized in earnings, as were the changes in fair value of the hedged item. Unrealized gains (losses) related to the fair value hedge and the related hedged item are shown in the table below:

(Millions)	Income Statement Presentation		2011		2010		2009
Interest rate swap	Interest expense	**$**		$	(1.7)	$	(0.6)
Debt hedged by swap	Interest expense				1.7		0.6
Total		**$**		$		$	

Fair value hedge ineffectiveness recorded in interest expense on the Statements of Income was not significant for 2011, 2010, and 2009. No amounts were excluded from effectiveness testing related to the interest rate swap during 2011, 2010, and 2009.

Cash Flow Hedges

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

In addition, we entered into interest rate swaps that were designated as cash flow hedges to hedge the variability in forecasted interest payments on debt issuance. The swaps were terminated when the related debt was issued.

Integrys Energy Services had the following notional volumes of outstanding contracts that were designated as cash flow hedges:

	December 31, 2011		**December 31, 2010**	
(Millions)	**Purchases**	**Sales**	**Purchases**	**Sales**
Commodity contracts				
Natural gas (therms)			265.6	
Electric (kilowatt-hours)			11,569.0	29.8

Table of Contents

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

Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)		
(Millions)	**2011**	**2010**
Natural gas contracts	**$ (2.3)**	$ (15.2)
Electric contracts	**3.8**	(13.6)
Interest rate swaps		(6.0)
Total	**$ 1.5**	$ (34.8)

Unrealized Gain (Loss) Recognized in OCI on Derivative Instruments (Effective Portion)	
(Millions)	**2009**
Commodity contracts	$ (60.0)
Interest rate swaps	3.2
Total	$ (56.8)

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	**Income Statement Presentation**	**2011**	**2010**
Settled/Realized			
Natural gas contracts	Nonregulated revenue	**$ (9.3)**	$ (16.4)
Electric contracts	Nonregulated revenue	**4.2**	(21.6)
Interest rate swaps	Interest expense	**(1.1)**	0.2
Hedge Designation Discontinued			
Natural gas contracts	Nonregulated revenue	**(0.3)**	0.2
Electric contracts	Nonregulated revenue		(9.9)
Interest rate swaps	Interest expense	**(0.2)**	
Total		**$ (6.7)**	$ (47.5)

Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)

(Millions)	**Income Statement Presentation**	**2009**
Settled/Realized		
Commodity contracts	Nonregulated revenue	$ (107.3)
Interest rate swaps	Interest expense	1.2
Hedge Designation Discontinued		
Commodity contracts	Nonregulated revenue	2.7
Total		$ (103.4)

Gain (Loss) Recognized in Income on Derivative Instruments
(Ineffective Portion and Amount Excluded from Effectiveness Testing)

(Millions)	**Income Statement Presentation**	**2011**	**2010**
Natural gas contracts	Nonregulated revenue	**$ 0.3**	$ (1.1)
Electric contracts	Nonregulated revenue	**(0.3)**	(0.5)
Total		**$**	$ (1.6)

Loss Recognized in Income on Derivative Instruments

	(Ineffective Portion and Amount Excluded from Effectiveness Testing)		
(Millions)	**Income Statement Presentation**	**2009**	
Commodity contracts	Nonregulated revenue	$	(1.1)

Table of Contents

NOTE 3 RESTRUCTURING EXPENSE

Reductions in Workforce

In an effort to remove costs from our operations, we developed a plan at the end of 2009 that included reductions in our workforce. In connection with this plan, employee-related and consulting costs were included in the restructuring expense line item on the Statements of Income. The restructuring costs were distributed across our segments as follows:

(Millions)	**2011**	**2010**