INTEGRYS ENERGY GROUP, INC.
Form 10-Q
November 06, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

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	Internal Revenue Service Employer Identification No.
1-11337	**INTEGRYS ENERGY GROUP, INC.** (A Wisconsin Corporation) 130 East Randolph Street Chicago, Illinois 60601-6207 (312) 228-5400	39-1775292

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No 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 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 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

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

Common stock, $1 par value,
78,287,906 shares outstanding at
October 30, 2012

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INTEGRYS ENERGY GROUP, INC.

QUARTERLY REPORT ON FORM 10-Q

For the Quarter Ended September 30, 2012

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Commonly Used Acronyms in this Quarterly Report on Form 10-Q

AFUDC	Allowance for Funds Used During Construction
AMRP	Accelerated Natural Gas Main Replacement Program
ASU	Accounting Standards Update
ATC	American Transmission Company LLC
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	United States Generally Accepted Accounting Principles
IBS	Integrys Business Support, LLC
ICC	Illinois Commerce Commission
ICR	Infrastructure Cost Recovery
ITF	Integrys Transportation Fuels, LLC (doing business as Trillium CNG)
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 Utilities 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

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Forward-Looking Statements

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are not guarantees of future results and conditions, 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 our Annual Report on Form 10-K for the year ended December 31, 2011, as may be amended or supplemented in Part II, Item 1A of our subsequently filed Quarterly Reports on Form 10-Q (including this report), and those identified below:

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

- Federal and state legislative and regulatory changes 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.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited) (Millions, except per share data)	Three Months Ended September 30 2012	 2011	Nine Months Ended September 30 2012	 2011
Utility revenues	**$ 582.3**	$ 596.2	**$ 2,116.9**	$ 2,435.7
Nonregulated revenues	**345.3**	338.2	**898.6**	1,130.1
Total revenues	**927.6**	934.4	**3,015.5**	3,565.8
Utility cost of fuel, natural gas, and purchased power	**228.2**	245.7	**926.4**	1,211.6
Nonregulated cost of sales	**263.9**	292.8	**730.4**	985.1
Operating and maintenance expense	**240.6**	240.3	**749.1**	760.4
Depreciation and amortization expense	**62.9**	61.8	**187.7**	185.3
Taxes other than income taxes	**23.8**	23.5	**74.0**	73.5
Operating income	**108.2**	70.3	**347.9**	349.9
Earnings from equity method investments	**22.2**	19.9	**65.5**	59.6
Miscellaneous income	**3.1**	1.0	**7.2**	4.1
Interest expense	**(29.9)**	(31.3)	**(90.0)**	(98.0)
Other expense	**(4.6)**	(10.4)	**(17.3)**	(34.3)
Income before taxes	**103.6**	59.9	**330.6**	315.6
Provision for income taxes	**29.4**	22.5	**106.3**	121.7
Net income from continuing operations	**74.2**	37.4	**224.3**	193.9
Discontinued operations, net of tax	**(7.9)**	0.2	**(8.7)**	(2.9)
Net income	**66.3**	37.6	**215.6**	191.0
Preferred stock dividends of subsidiary	**(0.7)**	(0.7)	**(2.3)**	(2.3)
Noncontrolling interest in subsidiaries	**0.1**		**0.1**	
Net income attributed to common shareholders	**$ 65.7**	$ 36.9	**$ 213.4**	$ 188.7
Average shares of common stock				
Basic	**78.5**	78.7	**78.5**	78.6
Diluted	**79.3**	79.2	**79.3**	78.9
Earnings (loss) per common share (basic)				
Net income from continuing operations	**$ 0.94**	$ 0.47	**$ 2.83**	$ 2.44
Discontinued operations, net of tax	**(0.10)**		**(0.11)**	(0.04)
Earnings per common share (basic)	**$ 0.84**	$ 0.47	**$ 2.72**	$ 2.40
Earnings (loss) per common share (diluted)				
Net income from continuing operations	**$ 0.93**	$ 0.47	**$ 2.80**	$ 2.43
Discontinued operations, net of tax	**(0.10)**		**(0.11)**	(0.04)

Earnings per common share (diluted)	**$**	**0.83**	$	0.47	**$**	**2.69**	$	2.39
Dividends per common share declared	**$**	**0.68**	$	0.68	**$**	**2.04**	$	2.04

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited) **(Millions)**	**Three Months Ended September 30** **2012**	**2011**	**Nine Months Ended September 30** **2012**	**2011**
Net income	**$ 66.3**	$ 37.6	**$ 215.6**	$ 191.0
Other comprehensive income, net of tax:				
Cash flow hedges				
Unrealized net gains (losses) arising during period, net of tax of $0.1 million, $- million, $(0.1) million, and $1.2 million, respectively	**0.1**	(0.4)	**(0.1)**	1.5
Reclassification of net losses to net income, net of tax of $1.0 million, $0.6 million, $2.6 million, and $3.4 million, respectively	**1.6**	1.3	**4.1**	5.4
Cash flow hedges, net	**1.7**	0.9	**4.0**	6.9
Defined benefit pension plans				
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.2 million, $0.2 million, $0.7 million, and $0.4 million, respectively	**0.4**	0.2	**1.1**	0.7
Other comprehensive income, net of tax	**2.1**	1.1	**5.1**	7.6
Comprehensive income	**68.4**	38.7	**220.7**	198.6
Preferred stock dividends of subsidiary	**(0.7)**	(0.7)	**(2.3)**	(2.3)
Noncontrolling interest in subsidiaries	**0.1**		**0.1**	
Comprehensive income attributed to common shareholders	**$ 67.8**	$ 38.0	**$ 218.5**	$ 196.3

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (Millions)	September 30 2012	December 31 2011
Assets		
Cash and cash equivalents	**$ 18.1**	$ 28.1
Collateral on deposit	**51.6**	50.9
Accounts receivable and accrued unbilled revenues, net of reserves of $42.0 and $47.1, respectively	**484.6**	737.7
Inventories	**320.7**	298.0
Assets from risk management activities	**158.3**	227.2
Regulatory assets	**117.6**	125.1
Assets held for sale	**13.0**	26.1
Deferred income taxes	**102.7**	94.2
Prepaid taxes	**129.9**	209.6
Other current assets	**23.1**	29.0
Current assets	**1,419.6**	1,825.9
Property, plant, and equipment, net of accumulated depreciation of $3,120.0 and $3,006.9, respectively	**5,473.0**	5,177.8
Regulatory assets	**1,621.2**	1,658.5
Assets from risk management activities	**42.7**	64.4
Equity method investments	**506.7**	476.3
Goodwill	**658.3**	658.4
Other long-term assets	**122.8**	121.9
Total assets	**$ 9,844.3**	$ 9,983.2
Liabilities and Equity		
Short-term debt	**$ 410.3**	$ 303.3
Current portion of long-term debt	**387.0**	250.0
Accounts payable	**368.1**	426.6
Liabilities from risk management activities	**192.9**	311.5
Accrued taxes	**45.5**	70.5
Regulatory liabilities	**80.3**	67.5
Liabilities held for sale	**27.4**	27.3
Other current liabilities	**243.7**	217.0
Current liabilities	**1,755.2**	1,673.7
Long-term debt	**1,708.1**	1,845.0
Deferred income taxes	**1,176.9**	1,070.7
Deferred investment tax credits	**47.6**	44.0
Regulatory liabilities	**354.2**	332.5
Environmental remediation liabilities	**594.9**	615.1
Pension and other postretirement benefit obligations	**530.5**	749.3
Liabilities from risk management activities	**61.2**	102.0
Asset retirement obligations	**413.5**	397.2
Other long-term liabilities	**139.3**	141.1
Long-term liabilities	**5,026.2**	5,296.9
Commitments and contingencies		
Common stock - $1 par value; 200,000,000 shares authorized; 78,287,906 shares issued; 77,907,270 shares outstanding	**78.3**	78.3

Additional paid-in capital		**2,571.5**		2,579.1
Retained earnings		**417.0**		363.6
Accumulated other comprehensive loss		**(37.4)**		(42.5)
Shares in deferred compensation trust		**(17.6)**		(17.1)
Total common shareholders equity		**3,011.8**		2,961.4
Preferred stock of subsidiary - $100 par value; 1,000,000 shares authorized; 511,882 shares issued; 510,495 shares outstanding		**51.1**		51.1
Noncontrolling interest in subsidiaries				0.1
Total liabilities and equity	**$**	**9,844.3**	$	9,983.2

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

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INTEGRYS ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited) (Millions)	Nine Months Ended September 30 2012	2011
Operating Activities		
Net income	$ **215.6**	$ 191.0
Adjustments to reconcile net income to net cash provided by operating activities		
Discontinued operations, net of tax	**8.7**	2.9
Depreciation and amortization expense	**187.7**	185.3
Recoveries and refunds of regulatory assets and liabilities	**12.6**	42.8
Net unrealized gains on energy contracts	**(42.8)**	(18.9)
Bad debt expense	**19.3**	27.3
Pension and other postretirement expense	**46.7**	54.1
Pension and other postretirement contributions	**(247.8)**	(109.7)
Deferred income taxes and investment tax credits	**86.8**	155.9
Equity income, net of dividends	**(13.4)**	(11.2)
Other	**32.9**	24.7
Changes in working capital		
Collateral on deposit	**(1.1)**	(9.8)
Accounts receivable and accrued unbilled revenues	**232.6**	295.5
Inventories	**(20.9)**	(71.4)
Other current assets	**66.9**	16.3
Accounts payable	**(45.1)**	(56.3)
Other current liabilities	**5.7**	(83.8)
Net cash provided by operating activities	**544.4**	634.7
Investing Activities		
Capital expenditures	**(437.8)**	(203.2)
Capital contributions to equity method investments	**(24.0)**	(25.6)
Acquisition of compressed natural gas fueling companies, net of cash acquired	**1.3**	(42.6)
Other	**11.7**	4.8
Net cash used for investing activities	**(448.8)**	(266.6)
Financing Activities		
Short-term debt, net	**107.0**	240.2
Repayment of notes payable		(10.0)
Issuance of long-term debt	**28.0**	
Repayment of long-term debt	**(28.2)**	(556.2)
Proceeds from stock option exercises	**54.9**	8.0
Shares purchased for stock-based compensation	**(85.1)**	(10.9)
Payment of dividends		
Preferred stock of subsidiary	**(2.3)**	(2.3)
Common stock	**(159.0)**	(153.4)
Payments made on derivative contracts related to divestitures classified as financing activities	**(27.9)**	(29.3)
Other	**0.5**	(3.5)
Net cash used for financing activities	**(112.1)**	(517.4)
Change in cash and cash equivalents - continuing operations	**(16.5)**	(149.3)
Change in cash and cash equivalents - discontinued operations		
Net cash provided by (used for) operating activities	**6.6**	(1.2)
Net cash used for investing activities	**(0.1)**	(0.9)
Net cash used for financing activities		(0.3)
Net change in cash and cash equivalents	**(10.0)**	(151.7)

Cash and cash equivalents at beginning of period		**28.1**		179.0
Cash and cash equivalents at end of period	**$**	**18.1**	$	27.3

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

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INTEGRYS ENERGY GROUP, INC. AND SUBSIDIARIES
CONDENSED NOTES TO FINANCIAL STATEMENTS

September 30, 2012

NOTE 1 FINANCIAL INFORMATION

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

We prepare our financial statements in conformity with the rules and regulations of the SEC for Quarterly Reports on Form 10-Q and in accordance with GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2011.

In management s opinion, these unaudited financial statements include all adjustments necessary for a fair presentation of financial results. All adjustments are normal and recurring, unless otherwise noted. All intercompany transactions have been eliminated in consolidation. Financial results for an interim period may not give a true indication of results for the year.

Reclassification

We reclassified $49.0 million of materials and supplies reported in other current assets at December 31, 2011, to inventories to be consistent with the current period presentation on the balance sheets. We adjusted changes in working capital on the statements of cash flows by reclassifying $10.1 million related to materials and supplies at September 30, 2011, from the change in other current assets line item to the change in inventories line item. This reclassification had no impact on total cash flows from operating activities.

NOTE 2 CASH AND CASH EQUIVALENTS

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

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

(Millions)	Nine Months Ended September 30 2012	2011
Cash paid for interest	**$ 60.0**	$ 80.3
Cash received for income taxes	**(45.7)**	(10.9)

Significant noncash transactions were:

(Millions)	Nine Months Ended September 30 2012	2011
Construction costs funded through accounts payable	**$ 78.8**	$ 34.1
Equity issued for stock-based compensation plans		15.8
Equity issued for reinvested dividends		5.4

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NOTE 3 RISK MANAGEMENT ACTIVITIES

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

(Millions)	Balance Sheet Presentation *	September 30, 2012 Assets from Risk Management Activities	September 30, 2012 Liabilities from Risk Management Activities
Utility Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**$ 9.4**	**$ 17.1**
Natural gas contracts	Long-term	**1.7**	**1.3**
Financial transmission rights (FTRs)	Current	**3.4**	**0.2**
Petroleum product contracts	Current	**0.3**	
Coal contract	Current		**5.0**
Coal contract	Long-term		**4.3**
Cash flow hedges			
Natural gas contracts	Current		**0.5**
Nonregulated Segments			
Non-hedge derivatives			
Natural gas contracts	Current	**70.7**	**67.0**
Natural gas contracts	Long-term	**15.6**	**11.6**
Electric contracts	Current	**74.5**	**103.0**
Electric contracts	Long-term	**25.4**	**44.1**
Foreign exchange contracts	Current	**0.1**	**0.1**
	Current	**158.4**	**192.9**
	Long-term	**42.7**	**61.3**
Total		**$ 201.1**	**$ 254.2**

* 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 upon the maturities of the underlying contracts.

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		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
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 upon the maturities of the underlying contracts.

The tables above include amounts that were classified as held for sale at Integrys Energy Services. The carrying values of our assets and liabilities from risk management activities that were classified as held for sale are shown in the table below. See Note 5, *Discontinued Operations,* for more information.

(Millions)	September 30, 2012	December 31, 2011
Nonregulated Segments		
Non-hedge derivatives		
Electric contracts		
Current assets from risk management activities	**$ 0.1**	$
Current liabilities from risk management activities		0.1
Long-term liabilities from risk management activities	**0.1**	

The following table shows our cash collateral positions:

(Millions)	September 30, 2012	December 31, 2011

Cash collateral provided to others	**$**	**51.6**	$	50.9
Cash collateral received from others *		**0.6**		2.3

* 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)		**September 30, 2012**		**December 31, 2011**
Integrys Energy Services	**$**	**112.0**	$	193.8
Utility segments		**15.3**		39.1

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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)		September 30, 2012	December 31, 2011
Collateral that would have been required:			
Integrys Energy Services		**$ 171.5**	$ 272.3
Utility segments		**9.9**	28.7
Collateral already satisfied:			
Integrys Energy Services	Letters of credit	**2.2**	11.0
Collateral remaining:			
Integrys Energy Services		**169.3**	261.3
Utility segments		**9.9**	28.7

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:

	September 30, 2012		December 31, 2011	
	Purchases	Other Transactions	Purchases	Other Transactions
Natural gas (millions of therms)	**1,044.1**	**N/A**	1,122.7	N/A
FTRs (millions of kilowatt-hours)	**N/A**	**6,507.6**	N/A	5,077.5
Petroleum products (barrels)	**61,814.0**	**N/A**	46,872.0	N/A
Coal contract (millions of tons)	**3.5**	**N/A**	4.1	N/A

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

(Millions)	Financial Statement Presentation		Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
Natural gas contracts	Balance Sheet	Regulatory assets (current)	**$ 10.2**	$ (9.3)	**$ 22.9**	$ 4.1

Natural gas contracts	Balance Sheet	Regulatory assets (long-term)	**3.8**	(2.5)	**7.7**	(2.3)
Natural gas contracts	Balance Sheet	Regulatory liabilities (current)	**(3.4)**	(0.1)	**(2.9)**	(0.2)
Natural gas contracts	Balance Sheet	Regulatory liabilities (long-term)	**0.8**		**1.3**	
Natural gas contracts	Income Statement	Utility cost of fuel, natural gas, and purchased power	**0.1**	(0.1)	**0.2**	
Natural gas contracts	Income Statement	Operating and maintenance expense	**0.1**		**0.1**	
FTRs	Balance Sheet	Regulatory assets (current)		0.5	**(0.4)**	(1.0)
FTRs	Balance Sheet	Regulatory liabilities (current)	**(0.2)**	(0.6)	**0.5**	(0.7)
Petroleum product contracts	Balance Sheet	Regulatory assets (current)	**0.2**		**0.1**	(0.1)
Petroleum product contracts	Balance Sheet	Regulatory liabilities (current)	**0.1**	(0.2)	**0.1**	
Petroleum product contracts	Income Statement	Operating and maintenance expense	**0.1**	(0.2)	**0.1**	
Coal contract	Balance Sheet	Regulatory assets (current)	**0.7**	1.1	**(2.5)**	0.9
Coal contract	Balance Sheet	Regulatory assets (long-term)	**(0.1)**	2.4	**0.1**	(0.6)
Coal contract	Balance Sheet	Regulatory liabilities (long-term)		0.5		(3.2)

Nonregulated Segments

Non-Hedge Derivatives

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

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

	September 30, 2012		December 31, 2011	
(Millions)	Purchases	Sales	Purchases	Sales
Commodity contracts				
Natural gas (therms)	**934.0**	**720.9**	959.2	797.1
Electric (kilowatt-hours)	**39,962.4**	**24,162.7**	34,405.7	20,374.0
Foreign exchange contracts (Canadian dollars)	**1.3**	**1.3**	4.2	4.2

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

		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	Income Statement Presentation	2012	2011	2012	2011
Natural gas contracts	Nonregulated revenue	**$ (4.4)**	$ 4.9	**$ 7.0**	$ 19.2
Natural gas contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(0.1)**	(0.2)	**(1.6)**	(0.6)
Electric contracts	Nonregulated revenue	**49.1**	(1.6)	**(10.5)**	(5.5)
Electric contracts	Nonregulated revenue (reclassified from accumulated OCI) *	**(1.9)**	(1.2)	**(3.3)**	(1.0)
Total		**$ 42.7**	$ 1.9	**$ (8.4)**	$ 12.1

* Represents amounts reclassified from accumulated OCI related to cash flow hedges that were dedesignated in prior periods.

In the next 12 months, pre-tax losses of $0.6 million and $4.1 million related to 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 customer contracts.

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.

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 contracts.

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)	**Three Months Ended September 30, 2011**		**Nine Months Ended September 30, 2011**	
Natural gas contracts	$		$	(2.3)
Electric contracts				3.8
Total	$		$	1.5

		Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)							
		Three Months Ended September 30				**Nine Months Ended September 30**			
(Millions)	**Income Statement Presentation**	**2012**		**2011**		**2012**		**2011**	
Settled/Realized									
Natural gas contracts	Nonregulated revenue	**$**		$		**$**		$	(9.3)
Electric contracts	Nonregulated revenue								4.2
Interest rate swaps *	Interest expense		**(0.2)**		(0.2)		**(0.8)**		(0.8)
Hedge Designation Discontinued									
Natural gas contracts	Nonregulated revenue								(0.3)
Interest rate swaps	Interest expense								(0.2)
Total		**$**	**(0.2)**	$	(0.2)	**$**	**(0.8)**	$	(6.4)

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

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

(Millions)	Income Statement Presentation	Three Months Ended September 30 2011	Nine Months Ended September 30 2011
Natural gas contracts	Nonregulated revenue	$	$ 0.3
Electric contracts	Nonregulated revenue		(0.3)
Total		$	$

NOTE 4 AGREEMENT TO PURCHASE FOX ENERGY CENTER

In September 2012, WPS entered into an agreement to acquire all of the equity interests in Fox Energy Company LLC. The purchase includes the Fox Energy Center, a 593-megawatt combined-cycle electric generating facility in Wisconsin, along with associated contracts. WPS currently supplies natural gas for the facility and purchases 500 megawatts of capacity and the associated energy output under a tolling arrangement.

WPS will pay $390.0 million to purchase Fox Energy Company LLC, subject to post-closing adjustments primarily related to working capital. In addition, WPS will pay $50.0 million to terminate the existing tolling arrangement immediately prior to the acquisition of the facility. The purchase will be financed initially with a combination of short-term debt and cash flow from operations. This short-term debt will be replaced later in 2013 with long-term financing.

Fox Energy Center is a dual-fuel facility, equipped to use fuel oil, but expected to run primarily on natural gas. This plant will give WPS a more balanced mix of electric generation, including coal, natural gas, hydroelectric, wind, and other renewable sources.

The transaction is subject to state regulatory approvals, including cost recovery, FERC approvals, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The transaction is expected to close on or around April 1, 2013.

NOTE 5 DISCONTINUED OPERATIONS

Integrys Energy Services Segment

Pending Sale of WPS Westwood Generation, LLC

In September 2012, Sunbury Holdings, LLC, a subsidiary of Integrys Energy Services, entered into a definitive agreement to sell all of the membership interests of WPS Westwood Generation, LLC (Westwood), owner of a waste coal generation plant located in Pennsylvania. The cash proceeds related to the sale are estimated to be $2.2 million, subject to certain post-closing adjustments primarily related to working capital. The agreement also includes a $4.0 million note receivable from the buyer with a seven and one-half year term. Integrys Energy Services recorded a pre-tax impairment loss of $8.4 million ($5.0 million after tax) related to Westwood during the third quarter of 2012 when the assets and liabilities were classified as held for sale. Other gains or losses may be recognized related to adjustments to selling costs at closing, as well as changes in the fair value of financial instruments included in the sale. Deferred financing costs of $0.4 million will also be written off to the gain or loss on sale when the related bonds are repaid, as discussed below. The transaction is expected to close in November 2012.

In connection with the sale, Integrys Energy Services repaid $27.0 million of Refunding Tax Exempt Bonds to Schuylkill County Industrial Development Authority in November 2012. The bonds were required to be repaid prior to the closing of the sale transaction because the Westwood assets were a substantial portion of the collateral on these borrowings. See Note 10, *Long-term Debt*, for more information regarding this repayment.

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

(Millions)	September 30, 2012	December 31, 2011
Inventories	$ **1.0**	$ 1.1
Current assets from risk management activities	**0.1**	
Property, plant, and equipment, net of accumulated depreciation of $ - and $10.9, respectively	**5.5**	14.1
Other long-term assets	**1.1**	1.2
Total assets	$ **7.7**	$ 16.4
Current liabilities from risk management activities	$	$ 0.1
Other current liabilities	**0.1**	0.2
Long-term debt	**27.0**	27.0
Long-term liabilities from risk management activities	**0.1**	
Total liabilities	$ **27.2**	$ 27.3

A summary of the components of discontinued operations related to Westwood recorded in the income statements for the three and nine months ended September 30 is as follows:

(Millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
Nonregulated revenues	$ **2.2**	$ 3.1	$ **8.2**	$ 7.9
Nonregulated cost of sales	**(1.2)**	(1.4)	**(3.6)**	(4.0)
Operating and maintenance expense	**(0.9)**	(0.9)	**(4.5)**	(4.8)
Impairment losses	**(8.4)**		**(8.4)**	
Depreciation and amortization expense	**(0.3)**	(0.4)	**(1.0)**	(1.1)
Taxes other than income taxes	**(0.1)**	(0.1)	**(0.2)**	(0.2)
Interest expense	**(0.1)**	(0.1)	**(0.4)**	(0.4)
Income (loss) before taxes	**(8.8)**	0.2	**(9.9)**	(2.6)
(Provision) benefit for income taxes	**3.5**	(0.1)	**3.9**	0.9
Discontinued operations, net of tax	$ **(5.3)**	$ 0.1	$ **(6.0)**	$ (1.7)

Integrys Energy Services will receive interest income for seven and one-half years related to the note receivable from the buyer. The sale will also generate immaterial cash flows from providing certain administrative transition services for up to a six-month period following the sale. However, Integrys Energy Services will not have the ability to significantly influence the operating or financial policies of Westwood and will also not have significant continuing involvement in the operations of Westwood after it is sold. Therefore, the continuing cash flows discussed above will not be considered direct cash flows of Westwood, and classification as a discontinued operation is appropriate.

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

In October 2012, WPS Empire State, Inc, a subsidiary of Integrys Energy Services, entered into a definitive agreement to sell all of the membership interests of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse), both of which own natural gas-fired generation plants located in the state of New York. The closing of this sale is contingent upon obtaining certain customary contractual consents and necessary regulatory approvals. The proceeds from the sale are estimated to be $1.8 million, subject to certain post-closing adjustments primarily related to working capital. The sale agreement also includes a potential annual payment to Integrys Energy Services for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). Integrys Energy Services recorded a pre-tax impairment loss of $4.0 million ($2.4 million after tax) related to Beaver Falls and Syracuse during the third quarter of 2012 when the assets and liabilities were classified as held for sale. Other gains or losses may be recognized related to adjustments to selling costs at closing, as well as changes in the fair value of financial instruments included in the sale. The transaction is expected to close by the end of the first quarter of 2013.

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

(Millions)	September 30, 2012	December 31, 2011
Inventories	**$ 2.2**	$ 2.2
Other current assets	**0.2**	0.2
Property, plant, and equipment, net of accumulated depreciation of $ - and $0.9, respectively	**2.8**	7.2
Other long-term assets	**0.1**	0.1
Total assets	**$ 5.3**	$ 9.7
Total liabilities other current liabilities	**$ 0.2**	$

A summary of the components of discontinued operations related to Beaver Falls and Syracuse recorded in the income statements for the three and nine months ended September 30 is as follows:

(Millions)	Three Months Ended September 30 2012	2011	Nine Months Ended September 30 2012	2011
Nonregulated revenues	**$ 1.2**	$ 2.0	**$ 1.5**	$ 4.8
Nonregulated cost of sales	**(0.7)**	(0.8)	**(1.6)**	(2.0)
Operating and maintenance expense	**(0.6)**	(0.6)	**(1.7)**	(2.3)
Impairment losses	**(4.0)**		**(4.0)**	
Depreciation and amortization expense	**(0.2)**	(0.2)	**(0.6)**	(0.5)
Taxes other than income taxes		(0.2)	**(1.1)**	(0.7)
Income (loss) before taxes	**(4.3)**	0.2	**(7.5)**	(0.7)
(Provision) benefit for income taxes	**1.7**	(0.1)	**3.0**	0.3
Discontinued operations, net of tax	**$ (2.6)**	$ 0.1	**$ (4.5)**	$ (0.4)

The sale of Beaver Falls and Syracuse will generate immaterial cash flows from providing certain administrative transition services for up to a six-month period following the sale and from a potential four-year earn-out payment. However, Integrys Energy Services will not have the ability to significantly influence the operating or financial policies of Beaver Falls and Syracuse and will also not have significant continuing involvement in the operations of Beaver Falls and Syracuse after they are sold. Therefore, the continuing cash flows discussed above will not be considered direct cash flows of Beaver Falls and Syracuse, and classification as a discontinued operation is appropriate.

Sale of Energy Management Consulting Business

During the nine months ended September 30, 2011, Integrys Energy Services recorded a $0.1 million after-tax gain in discontinued operations when contingent payments were earned related to the 2009 sale of its energy management consulting business.

Holding Company and Other Segment

Discontinued operations were also recorded at the holding company and other segment. Uncertain tax positions included in our liability for unrecognized tax benefits were remeasured to better reflect how the underlying positions are resolving themselves in various taxing jurisdictions. We also effectively settled certain state income tax examinations in 2012. During the nine months ended September 30, 2012 and September 30, 2011, we recorded a $1.8 million after-tax gain and a $0.9 million after-tax loss, respectively, in discontinued operations.

NOTE 6 INVESTMENT IN ATC

Our electric transmission investment segment consists of WPS Investments LLC s ownership interest in ATC, which was approximately 34% at September 30, 2012. ATC is a for-profit, transmission-only company regulated by FERC. ATC owns, maintains, monitors, and operates electric transmission assets in portions of Wisconsin, Michigan, Minnesota, and Illinois.

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The following table shows changes to our investment in ATC.

(Millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
Balance at the beginning of period	**$ 456.4**	$ 429.4	**$ 439.4**	$ 416.3
Add: Equity in net income	**21.7**	19.9	**63.8**	59.0
Add: Capital contributions	**8.5**	2.6	**17.0**	8.5
Less: Dividends received	**17.3**	16.2	**50.9**	48.1
Balance at the end of period	**$ 469.3**	$ 435.7	**$ 469.3**	$ 435.7

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

(Millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011
Income statement data				
Revenues	**$ 150.3**	$ 142.8	**$ 450.1**	$ 420.6
Operating expenses	**68.8**	66.4	**210.1**	192.5
Other expense	**21.0**	19.8	**62.1**	61.6
Net income *	**$ 60.5**	$ 56.6	**$ 177.9**	$ 166.5

* As most income taxes are the responsibility of its members, ATC does not report a provision for its members income taxes in its income statements.

(Millions)	September 30, 2012	December 31, 2011
Balance sheet data		
Current assets	**$ 58.2**	$ 58.7
Noncurrent assets	**3,237.0**	3,053.7
Total assets	**$ 3,295.2**	$ 3,112.4
Current liabilities	**$ 232.0**	$ 298.5
Long-term debt	**1,550.0**	1,400.0
Other noncurrent liabilities	**93.9**	82.6
Members equity	**1,419.3**	1,331.3
Total liabilities and members equity	**$ 3,295.2**	$ 3,112.4

NOTE 7 INVENTORIES

PGL and NSG price natural gas storage injections at the calendar year average of the cost of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. At September 30, 2012, all LIFO layers were replenished and the LIFO liquidation balance was zero.

NOTE 8 GOODWILL AND OTHER INTANGIBLE ASSETS

We had no material changes to the carrying amount of goodwill during the nine months ended September 30, 2012, and 2011. Annual impairment tests were completed at all of our reporting units that carried a goodwill balance in the second quarter of 2012, and no impairments resulted from these tests.

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

(Millions)	September 30, 2012			December 31, 2011		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets						
Customer-related (1)	**$ 22.4**	**$ (14.3)**	**$ 8.1**	$ 34.5	$ (24.8)	$ 9.7
Electric contract assets (2)				7.8	(6.6)	1.2
Patents (3)	**7.2**	**(0.2)**	**7.0**	7.2		7.2
Compressed natural gas fueling contract assets (4)	**5.6**	**(1.1)**	**4.5**	5.6	(0.3)	5.3
Renewable energy credits (5)	**3.2**		**3.2**	2.8		2.8
Nonregulated easements (6)	**3.8**	**(0.8)**	**3.0**	3.8	(0.7)	3.1
Customer-owned equipment modifications (7)	**3.9**	**(0.5)**	**3.4**	3.6	(0.2)	3.4
Emission allowances (8)	**0.8**	**(0.1)**	**0.7**	1.7	(0.2)	1.5
Other	**0.9**	**(0.3)**	**0.6**	1.4	(0.3)	1.1
Total	**$ 47.8**	**$ (17.3)**	**$ 30.5**	$ 68.4	$ (33.1)	$ 35.3
Unamortized intangible assets						
MGU trade name	**$ 5.2**		**$ 5.2**	$ 5.2		$ 5.2
Trillium trade name	**3.5**		**3.5**	3.5		3.5
Pinnacle trade name	**1.5**		**1.5**	1.5		1.5
Total intangible assets	**$ 58.0**	**$ (17.3)**	**$ 40.7**	$ 78.6	$ (33.1)	$ 45.5

(1) Represents customer relationship assets associated with PELLC s former nonregulated retail natural gas and electric operations, MERC s nonutility ServiceChoice business, and Trillium USA (Trillium) and Pinnacle CNG Systems (Pinnacle) compressed natural gas fueling operations. The remaining weighted-average amortization period for customer-related intangible assets at September 30, 2012, was approximately 10 years.

(2) Represents electric customer contracts acquired in exchange for risk management assets.

(3) Represents the fair value of patents at Pinnacle related to a system for more efficiently compressing natural gas to allow for faster fueling. The remaining amortization period at September 30, 2012, was approximately 17 years.

(4) Represents the fair value of Trillium and Pinnacle compressed natural gas customer fueling contracts acquired in September 2011. The remaining amortization period at September 30, 2012, was approximately 8 years.

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

(6) Relates to easements supporting a pipeline at Integrys Energy Services. The easements are amortized on a straight-line basis, with a remaining amortization period at September 30, 2012, of approximately 12 years.

(7) Relates to modifications made by Integrys Energy Services and Trillium to customer-owned equipment. These intangible assets are amortized on a straight-line basis, with a remaining weighted-average amortization period at September 30, 2012, of approximately 12 years.

(8) Emission allowances do not have a contractual term or expiration date.

Amortization expense recorded as a component of nonregulated cost of sales in the statements of income was $0.3 million and $0.2 million for the three months ended September 30, 2012, and 2011, respectively. Amortization expense for the nine months ended September 30, 2012, and 2011, was $2.2 million and $0.8 million, respectively.

Amortization expense recorded as a component of depreciation and amortization expense in the statements of income for the three months ended September 30, 2012, and 2011, was $0.5 million and $0.8 million, respectively. Amortization expense for the nine months ended September 30, 2012, and 2011, was $2.0 million and $2.5 million, respectively.

An insignificant amount of amortization expense was recorded in discontinued operations for the three and nine months ended September 30, 2012, and 2011.

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

	For the year ending December 31				
(Millions)	2012	2013	2014	2015	2016
Amortization recorded in nonregulated cost of sales	$ 5.7	$ 1.6	$ 1.2	$ 1.1	$ 0.9
Amortization recorded in depreciation and amortization expense	2.5	2.0	1.7	1.7	1.5

NOTE 9 SHORT-TERM DEBT AND LINES OF CREDIT

Our short-term borrowings were as follows:

(Millions, except percentages)	September 30, 2012	December 31, 2011
Commercial paper outstanding	**$ 410.3**	$ 303.3
Average discount rate on outstanding commercial paper	**0.35%**	0.31%

The commercial paper outstanding at September 30, 2012, had maturity dates ranging from October 1, 2012, through October 24, 2012.

The table below presents our average amount of short-term borrowings outstanding based on daily outstanding balances during the nine months ended September 30:

(Millions)	2012	2011
Average amount of commercial paper outstanding	**$ 299.2**	$ 102.2
Average amount of short-term notes payable outstanding		4.8

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

(Millions)	Maturity	September 30, 2012	December 31, 2011
Revolving credit facility (Integrys Energy Group) (1)	04/23/13	**$**	$ 735.0
Revolving credit facility (Integrys Energy Group)	05/17/14	**275.0**	275.0
Revolving credit facility (Integrys Energy Group)	05/17/16	**200.0**	200.0
Revolving credit facility (Integrys Energy Group)	06/13/17	**635.0**	

Revolving credit facility (WPS) (1)	04/23/13				115.0
Revolving credit facility (WPS) (2)	06/12/13		**115.0**		
Revolving credit facility (WPS)	05/17/14		**135.0**		135.0
Revolving credit facility (PGL) (1)	04/23/13				250.0
Revolving credit facility (PGL)	06/13/17		**250.0**		
Total short-term credit capacity		**$**	**1,610.0**	$	1,710.0
Less:					
Letters of credit issued inside credit facilities		**$**	**24.4**	$	33.7
Commercial paper outstanding			**410.3**		303.3
Available capacity under existing agreements		**$**	**1,175.3**	$	1,373.0

(1) These credit facilities were terminated in June 2012.

(2) WPS requested approval from the PSCW to extend this facility through June 13, 2017.

In connection with the pending purchase of Fox Energy Company LLC, WPS requested approval from the PSCW to temporarily increase its short-term debt limit. See Note 4, *Agreement to Purchase Fox Energy Center,* for more information regarding this pending purchase.

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NOTE 10 LONG-TERM DEBT

(Millions)	September 30, 2012	December 31, 2011
WPS (1)	**$ 722.1**	$ 722.1
PGL (2)	**525.0**	525.0
NSG (3)	**74.5**	74.7
Integrys Energy Group (4)	**774.8**	774.8
Other term loan (5)	**27.0**	27.0
Total	**2,123.4**	2,123.6
Unamortized discount	**(1.3)**	(1.6)
Total debt	**2,122.1**	2,122.0
Less current portion	**(387.0)**	(250.0)
Less long-term debt held for sale (5)	**(27.0)**	(27.0)
Total long-term debt	**$ 1,708.1**	$ 1,845.0

(1) In December 2012, WPS s 4.875% Senior Notes will mature. As a result, the $150.0 million balance of these notes was included in the current portion of long-term debt on our balance sheets.

In February 2013, WPS s 3.95% Senior Notes will mature. As a result, the $22.0 million balance of these notes was included in the current portion of long-term debt on our September 30, 2012 balance sheet.

(2) In May 2013, PGL s 4.625% Series NN-2 Fixed First and Refunding Mortgage Bonds will mature. As a result, the $75.0 million balance of these bonds was included in the current portion of long-term debt on our September 30, 2012 balance sheet.

(3) In April 2012, NSG bought back its $28.2 million of 5.00% Series M First Mortgage Bonds that were due December 1, 2028.

In the same month, NSG issued $28.0 million of 3.43% Series P First Mortgage Bonds. These bonds are due April 1, 2027.

In May 2013, NSG s 4.625% Series N-2 First Mortgage Bonds will mature. As a result, the $40.0 million balance of these bonds was included in the current portion of long-term debt on our September 30, 2012 balance sheet.

(4) In December 2012, our 5.375% Unsecured Senior Notes will mature. As a result, the $100.0 million balance of these notes was included in the current portion of long-term debt on our balance sheets.

(5) This loan was repaid in November 2012 in connection with the pending sale of WPS Westwood Generation, LLC. As a result, the $27.0 million balance of this loan was included in liabilities held for sale on our balance sheets. See Note 5, *Discontinued Operations,* for more information regarding the pending sale. This loan had a floating interest rate that was reset weekly. At September 30, 2012, the interest rate was 0.19%.

In October 2012, PGL secured commitments for $100.0 million of 30-year 3.98% Series YY First and Refunding Mortgage Bonds with a delayed draw feature. These bonds will be issued in December 2012.

NOTE 11 INCOME TAXES

We calculate our interim period provision for income taxes based on our projected annual effective tax rate as adjusted for certain discrete items.

The table below shows our effective tax rates:

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	**2011**	**2012**	**2011**
Effective Tax Rate	**28.4%**	37.6%	**32.2%**	38.6%

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

Our effective tax rate for the three months ended September 30, 2012, was impacted by a $5.9 million decrease in the provision for income taxes resulting from WPS s 2013 rate case settlement agreement. In the third quarter of 2012, WPS recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. See Note 20, *Regulatory Environment,* for more information. Our effective tax rate was also impacted by the federal income tax benefit of tax credits related to wind production and other miscellaneous tax adjustments.

Our effective tax rate for the nine months ended September 30, 2012, was impacted by the settlement of certain state income tax examinations and the remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits in 2012. We decreased our provision for income taxes $6.2 million in 2012 primarily related to the effective settlement and remeasurement of these positions. Finally, our provision for income taxes decreased $5.9 million in 2012 related to the impact of WPS s 2013 rate case settlement agreement, as described above. Our effective tax rate was also impacted by the federal income tax benefit of tax credits related to wind production.

Our effective tax rate for the nine months ended September 30, 2011, was impacted by the federal income tax benefit of tax credits related to wind production and tax law changes in Michigan and Wisconsin. We recorded $6.0 million of income tax expense in 2011 when we increased our deferred income tax liabilities related to these tax law changes.

During the three months ended September 30, 2012, there was not a significant change in our liability for unrecognized tax benefits. During the nine months ended September 30, 2012, we decreased our liability for unrecognized tax benefits by $8.3 million. This decrease related to the effective settlement of certain state income tax examinations and a remeasurement of uncertain tax positions, as described above. We reduced the provision for income taxes related to these items, of which a portion was reported as discontinued operations.

NOTE 12 COMMITMENTS AND CONTINGENCIES

Commodity Purchase Obligations and Purchase Order Commitments

We and our subsidiaries routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. The regulated natural gas utilities have obligations to distribute and sell natural gas to their customers, and the regulated electric utilities have obligations to distribute and sell electricity to their customers. The utilities expect to recover costs related to these obligations in future customer rates. Additionally, the majority of the energy supply contracts entered into by Integrys Energy Services are to meet its obligations to deliver energy to customers.

The purchase obligations described below were as of September 30, 2012.

- The electric utility segment had obligations of $1,018.3 million for either capacity or energy related to purchased power that extend through 2029, obligations of $165.4 million related to coal supply and transportation contracts that extend through 2017, and obligations of $0.9 million for other commodities that extend through 2013.
- The natural gas utility segment had obligations of $773.4 million related to natural gas supply and transportation contracts that extend through 2028.
- Integrys Energy Services had obligations of $268.5 million, primarily related to electricity and natural gas supply contracts that extend through 2020.
- We and our subsidiaries also had commitments of $410.3 million in the form of purchase orders issued to various vendors that relate to normal business operations, including construction projects.

Environmental

Clean Air Act (CAA) New Source Review Issues

Weston and Pulliam Plants:

In November 2009, the EPA issued a Notice of Violation (NOV) to WPS alleging violations of the CAA s New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009.

In May 2010, WPS received from the Sierra Club a Notice of Intent (NOI) to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended on October 6, 2012, but further action by the Sierra Club is unknown at this time.

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WPS believes it has reached a tentative agreement with the EPA on general terms to settle these air permitting violation claims and is negotiating a consent decree based upon those general terms, which are subject to change during the negotiations. Based upon the status of the current negotiations and a review of existing EPA consent decrees, WPS anticipates that the final consent decree could include the installation of emission control technology, changed operating conditions (including fuels other than coal and retirement of units), limitations on emissions, beneficial supplemental environmental projects, and a civil fine. Once the final terms are agreed to, the U.S. District Court must approve the consent decree after a public comment process.

WPS cannot predict the final outcome of this matter because a final agreement on the consent decree may not be reached, the final terms of the consent decree may be different than currently anticipated, interveners could convince the court to make changes to the terms of the consent decree during the public comment process, or the court may not approve the final consent decree.

Any costs prudently incurred as a result of actions taken due to the consent decree are expected to be recoverable from customers. We are currently unable to estimate the possible loss or range of loss related to this matter.

Columbia and Edgewater Plants:

In December 2009, the EPA issued an NOV to Wisconsin Power and Light (WP&L), the operator of the Columbia and Edgewater plants, and the other joint owners of these plants (including WPS). The NOV alleges violations of the CAA s New Source Review requirements related to certain projects completed at those plants.

In September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Columbia plant did not comply with the CAA. The case has been dismissed without prejudice as the parties continue to participate in settlement negotiations.

Also in September 2010, the Sierra Club filed a lawsuit against WP&L, which included allegations that modifications made at the Edgewater plant did not comply with the CAA. The case was stayed until July 15, 2012, and a request was made by WP&L to further extend the stay and all deadlines. An update was filed with the court on August 31, 2012, regarding the settlement negotiations with the Sierra Club, the EPA, and the joint owners of the Edgewater plant.

WPS, WP&L, and Madison Gas and Electric (Joint Owners), along with the EPA and the Sierra Club (collectively, the Parties) are exploring settlement options. The Joint Owners believe that the Parties have reached a tentative agreement on general terms to settle these air permitting violation claims and are negotiating a consent decree based upon those general terms, which are subject to change during the negotiations. Based upon the status of the current negotiations and a review of existing EPA consent decrees, WPS anticipates that the final consent decree could include the installation of emission control technology, changed operating conditions (including fuels other than coal and retirement of units), limitations on emissions, beneficial supplemental environmental projects, and a civil fine. Once the Parties agree to the final terms, the U.S. District Court must approve the consent decree after a public comment process.

WPS cannot predict the final outcome of this matter because the Parties may be unable to reach a final agreement on the consent decree, the final terms of the consent decree may be different than currently anticipated, interveners could convince the court to make changes to the terms of the consent decree during the public comment process, or the court may not approve the final consent decree.

Any costs prudently incurred as a result of actions taken due to the consent decree are expected to be recoverable from customers. We are currently unable to estimate the possible loss or range of loss related to this matter.

Weston Air Permits

Weston 4 Construction Permit:

From 2004 to 2009, the Sierra Club filed various petitions objecting to the construction permit issued for the Weston 4 plant. In June 2010, the Wisconsin Court of Appeals affirmed the Weston 4 construction permit, but directed the WDNR to reopen the permit to set specific visible emissions limits. In July 2010, the WDNR, WPS, and the Sierra Club filed Petitions for Review with the Wisconsin Supreme Court. In March 2011, the Wisconsin Supreme Court denied all Petitions for Review. Other than the specific visible emissions limits issue, all other challenges to the construction permit are now resolved. WPS is working with the WDNR and the Sierra Club to resolve this issue. We do not expect this matter to have a material impact on our financial statements.

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Weston Title V Air Permit:

In November 2010, the WDNR provided a draft revised permit. WPS objected to proposed changes in mercury limits and requirements on the boilers as beyond the authority of the WDNR. WPS and the WDNR continue to meet to resolve these issues. In September 2011, the WDNR issued an updated draft revised permit and a request for public comments. Due to the significance of the changes to the draft permit, the WDNR intends to re-issue the draft permit for additional comments. On July 24, 2012, Clean Wisconsin filed suit against the WDNR alleging failure to issue or delay in issuing the Weston 4 Title V permit. WPS is not a party to this litigation, but filed a request for intervention to protect its interests. Motions regarding intervention and dismissal have also been filed by WPS and the WDNR. We do not expect this matter to have a material impact on our financial statements.

WDNR Issued NOVs:

Since 2008, WPS received four NOVs from the WDNR alleging various violations of the different air permits for the entire Weston plant, Weston 1, Weston 2, and Weston 4, as well as one NOV for a clerical error involving pages missing from a quarterly report for Weston. Corrective actions have been taken for the events in the five NOVs. In December 2011, the WDNR dismissed two of the NOVs and referred the other three NOVs to the state Justice Department for enforcement. WPS and the Justice Department have begun discussing the pending NOVs and their resolution. We do not expect this matter to have a material impact on our financial statements.

Pulliam Title V Air Permit

The WDNR issued the renewal of the permit for the Pulliam plant in April 2009. In June 2010, the EPA issued an order directing the WDNR to respond to comments raised by the Sierra Club in its June 2009 Petition requesting the EPA to object to the permit.

WPS also challenged the permit in a contested case proceeding and Petition for Judicial Review. The Petition was dismissed in an order remanding the matter to the WDNR. In February 2011, the WDNR granted a contested case proceeding before an Administrative Law Judge on the issues raised by WPS, which included seeking averaging times in the emission limits in the permit. WPS participated in the contested case proceeding in October 2011. In December 2011, the Administrative Law Judge did not require the WDNR to insert averaging times, for which WPS had argued. WPS has decided not to appeal.

In October 2010, WPS received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA based on what the Sierra Club alleged to be an unreasonable delay in responding to the June 2010 order. WPS received notification that the Sierra Club filed suit against the EPA in April 2011. WPS is not a party to this litigation, but intervened to protect its interests. In February 2012, the WDNR sent a proposed permit and response to the EPA for a 45-day review, which allowed the parties to enter into a settlement agreement that has been entered by the court. On May 9, 2012, the Sierra Club filed another Petition requesting the EPA to again object to the proposed permit and response. The Sierra Club recently filed a request for a contested case proceeding regarding the permit, which WPS plans to oppose.

We are reviewing all of these matters, but we do not expect them to have a material impact on our financial statements.

Columbia Title V Air Permit

In October 2009, the EPA issued an order objecting to the permit renewal issued by the WDNR for the Columbia plant. The order determined that the WDNR did not adequately analyze whether a project in 2006 constituted a major modification that required a permit. The EPA s order directed the WDNR to resolve the objections within 90 days and terminate, modify, or revoke and reissue the permit accordingly.

In July 2010, WPS, along with its co-owners, received from the Sierra Club a copy of an NOI to file a civil lawsuit against the EPA. The Sierra Club alleges that the EPA should assert jurisdiction over the permit because the WDNR failed to respond to the EPA s objection within 90 days.

In September 2010, the WDNR issued a draft construction permit and a draft revised Title V permit in response to the EPA s order. In November 2010, the EPA notified the WDNR that the EPA does not believe the WDNR s proposal is responsive to the order. In January 2011, the WDNR issued a letter stating that upon review of the submitted public comments, the WDNR has determined not to issue the draft permits that were proposed to respond to the EPA s order. In February 2011, the Sierra Club filed for a declaratory action, claiming that the EPA had to assert jurisdiction over the permits. In May 2011, the WDNR issued a second draft Title V permit in response to the EPA s order.

In June 2012, WP&L received notice from the EPA of the EPA s proposal for WP&L to apply for a federally-issued Title V permit since the WDNR has not addressed the EPA s objections to the Title V permit issues for the Columbia plant. The notice gave WP&L 90 days to comment on the EPA s proposal, which was later extended by the EPA to December 15, 2012. If the EPA decides to require the submittal of an operation permit, it would be due within six months of the EPA s notice to WP&L. WP&L believes the previously issued Title V permit for the Columbia plant is still valid. We do not expect this matter to have a material impact on our financial statements.

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Mercury and Interstate Air Quality Rules

Mercury:

The State of Wisconsin s mercury rule, Chapter NR 446, requires a 40% reduction from the 2002 through 2004 baseline mercury emissions in Phase I, beginning January 1, 2010, through the end of 2014. In Phase II, which begins in 2015, electric generating units above 150 megawatts will be required to reduce mercury emissions by 90% from the 2002 through 2004 baseline. Reductions can be phased in and the 90% target delayed until 2021 if additional sulfur dioxide and nitrogen oxide reductions are implemented. By 2015, electric generating units above 25 megawatts but less than 150 megawatts must reduce their mercury emissions to a level defined by the Best Available Control Technology rule. As of September 30, 2012, WPS estimates capital costs of approximately $2 million, which includes estimates for both wholly owned and jointly owned plants, to achieve the required Phase I and Phase II reductions. The capital costs are expected to be recovered in future rates.

In December 2011, the EPA issued the final Utility Mercury and Air Toxics rule that will regulate emissions of mercury and other hazardous air pollutants beginning in 2015. We are currently evaluating options for achieving the emission limits specified in this rule, but we do not anticipate the cost of compliance to be significant. We expect to recover future compliance costs in future rates.

Sulfur Dioxide and Nitrogen Oxide:

The EPA issued the Clean Air Interstate Rule (CAIR) in 2005 in order to reduce sulfur dioxide and nitrogen oxide emissions from utility boilers located in 29 states, including Wisconsin, Michigan, Pennsylvania, and New York. In July 2008, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision vacating CAIR. In response to requests by numerous parties, including the EPA, the D.C. Circuit reinstated CAIR in December 2008, but directed the EPA to address the deficiencies noted in its previous ruling to vacate CAIR. In July 2011, the EPA issued a final CAIR replacement rule known as the Cross State Air Pollution Rule (CSAPR), which numerous parties, including WPS, challenged in the D.C. Circuit. The new rule was to become effective January 1, 2012; however, on December 30, 2011, the D.C. Circuit issued a decision that stayed the rule pending resolution of the challenges and directed the EPA to implement CAIR during the stay period. On August 21, 2012, the D.C. Circuit issued their ruling vacating and remanding CSAPR and simultaneously reinstating CAIR pending the issuance of a replacement rule by the EPA. On October 5, 2012, the EPA and several other parties filed petitions for rehearing of the D.C. Circuit s decision. Responses to those petitions are due November 16, 2012.

Under CAIR, units affected by the Best Available Retrofit Technology (BART) rule were considered in compliance with BART for sulfur dioxide and nitrogen oxide emissions if they were in compliance with CAIR. This determination was updated when CSAPR was issued (CSAPR satisfied BART) and the EPA has not revised it to reflect the reinstatement of CAIR. Although particulate emissions also contribute to visibility impairment, the WDNR s modeling has shown the impairment to be so insignificant that additional capital expenditures on controls are not warranted.

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

Manufactured Gas Plant Remediation

Our natural gas utilities, their predecessors, and certain former affiliates operated facilities in the past at multiple sites for the purpose of manufacturing and storing manufactured gas. In connection with these activities, waste materials were produced that may have resulted in soil and groundwater contamination at these sites. Under certain laws and regulations relating to the protection of the environment, our natural gas utilities are required to undertake remedial action with respect to some of these materials. They are coordinating the investigation and cleanup of the sites subject to EPA jurisdiction under what is called a multi-site program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies.

Our natural gas utilities are responsible for the environmental remediation of 53 sites, of which 20 have been transferred to the EPA Superfund Alternative Sites Program. Under the EPA s program, the remedy decisions at these sites will be made using risk-based criteria typically used at Superfund sites. As of September 30, 2012, we estimated and accrued for $593.3 million of future undiscounted investigation and cleanup costs for all sites. We may adjust these estimates in the future due to remedial technology, regulatory requirements, remedy determinations, and any claims of natural resource damages. As of September 30, 2012, cash expenditures for environmental remediation not yet recovered in rates were $34.5 million. We recorded a regulatory asset of $627.8 million at September 30, 2012, which is net of insurance recoveries received of $60.0 million, related to the expected recovery of both cash expenditures and estimated future expenditures through rates.

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

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NOTE 13 GUARANTEES

The following table shows our outstanding guarantees:

(Millions)	Total Amounts Committed at September 30, 2012	Less Than 1 Year	Expiration 1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	**$ 654.6**	$ 408.8	$ 28.8	$ 217.0
Standby letters of credit (2)	**57.4**	27.6	29.7	0.1
Surety bonds (3)	**15.9**	15.9		
Other guarantees (4)	**42.9**	20.0		22.9
Total guarantees	**$ 770.8**	$ 472.3	$ 58.5	$ 240.0

(1) Consists of parental guarantees of $494.5 million to support the business operations of Integrys Energy Services; $107.3 million and $45.8 million, respectively, related to natural gas supply at MERC and MGU; and $5.0 million at IBS, and $2.0 million at UPPCO to support business operations. These guarantees are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. This amount consists of $55.1 million issued to support Integrys Energy Services operations and $2.3 million issued to support MERC, MGU, NSG, PGL, Pinnacle CNG Systems, UPPCO, and WPS. These amounts are not reflected on our balance sheets. The Integrys Energy Services amount includes a $27.3 million letter of credit that was canceled as a result of the repayment of the WPS Westwood Generation, LLC loan in November 2012. See Note 10, Long-term Debt, for more information regarding this repayment.

(3) Primarily for workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These guarantees are not reflected on our balance sheets.

(4) Consists of (a) $20.0 million related to the sale agreement for Integrys Energy Services United States wholesale electric marketing and trading business, which included a number of customary representations, warranties, and indemnification provisions. This amount is not reflected on our balance sheets; (b) $10.0 million related to the sale agreement for Integrys Energy Services Texas retail marketing business, which included a number of customary representations, warranties, and indemnification provisions. An insignificant liability was recorded related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the tax law; (c) $5.0 million related to an environmental indemnification provided by Integrys Energy Services as part of the sale of the Stoneman generation facility, under which we expect that the likelihood of required performance is remote. This amount is not reflected on our balance sheets; and (d) $7.9 million related to other indemnifications primarily for workers compensation coverage. These amounts are not reflected on our balance sheets.

We have provided total parental guarantees of $588.3 million on behalf of Integrys Energy Services as shown in the table below. Our exposure under these guarantees related to existing transactions at September 30, 2012, was approximately $212.5 million.

(Millions)		September 30, 2012
Guarantees supporting commodity transactions	$	**494.5**
Standby letters of credit		**55.1**
Surety bonds		**3.2**
Other		**35.5**
Total guarantees	**$**	**588.3**

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NOTE 14 EMPLOYEE BENEFIT PLANS

As of February 16, 2012, our defined benefit pension plans were closed to all new hires.

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

	Pension Benefits				Other Postretirement Benefits			
	Three Months Ended September 30		Nine Months Ended September 30		Three Months Ended September 30		Nine Months Ended September 30	
(Millions)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Service cost	**$ 11.5**	$ 10.3	**$ 34.5**	$ 31.0	**$ 5.2**	$ 4.8	**$ 15.6**	$ 14.3
Interest cost	**19.5**	20.0	**58.5**	60.1	**7.1**	7.3	**21.4**	22.1
Expected return on plan assets	**(27.0)**	(25.0)	**(80.9)**	(75.0)	**(7.1)**	(5.4)	**(21.2)**	(16.1)
Amortization of transition obligation					**0.1**	0.1	**0.2**	0.2
Amortization of prior service cost (credit)	**1.3**	1.4	**3.8**	4.0	**(0.9)**	(0.9)	**(2.6)**	(2.9)
Amortization of net actuarial loss	**8.5**	4.6	**25.5**	13.6	**1.7**	1.0	**5.0**	3.0
Net periodic benefit cost	**$ 13.8**	$ 11.3	**$ 41.4**	$ 33.7	**$ 6.1**	$ 6.9	**$ 18.4**	$ 20.6

Transition obligations, prior service costs (credits), and net actuarial losses that have not yet been recognized as a component of net periodic benefit cost are included in accumulated OCI for our nonregulated entities and are recorded as net regulatory assets for our utilities.

We make contributions to our plans in accordance with legal and tax requirements. These contributions do not necessarily occur evenly throughout the year. We contributed $173.0 million to our pension plans and $75.1 million to our other postretirement benefit plans during the nine months ended September 30, 2012. Included in these contributions was an insignificant contribution related to WPS Westwood Generation, LLC, which is reflected in discontinued operations on the Statement of Cash Flows due to its pending sale. See Note 5, *Discontinued Operations,* for more information. We expect to contribute an additional $3.0 million to our pension plans and $39.1 million to our other postretirement benefit plans during the remainder of 2012, dependent upon various factors affecting us, including our liquidity position and tax law changes.

NOTE 15 STOCK-BASED COMPENSATION

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

(Millions)	Three Months Ended September 30 2012	2011	Nine Months Ended September 30 2012	2011
Stock options	**$ 0.5**	$ 0.4	**$ 1.5**	$ 1.4
Performance stock rights	**0.5**		**4.8**	1.2
Restricted shares and restricted share units	**2.1**	2.0	**7.5**	7.3
Total stock-based compensation expense	**$ 3.1**	$ 2.4	**$ 13.8**	$ 9.9
Deferred income tax benefit	**$ 1.2**	$ 1.0	**$ 5.5**	$ 4.0

No stock-based compensation cost was capitalized during the three and nine months ended September 30, 2012, and 2011.

Stock Options

The fair value of stock option awards granted is estimated using a binomial lattice model. The expected term of option awards is calculated based on historical exercise behavior and represents the period of time that options are expected to be outstanding. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. Our expected stock price volatility is estimated using its 10-year historical volatility. The following table shows the weighted-average fair value per stock option granted during the nine months ended September 30, 2012, along with the assumptions incorporated into the valuation model:

	February 2012 Grant
Weighted-average fair value per option	**$6.30**
Expected term	**5 years**
Risk-free interest rate	**0.17% - 2.18%**
Expected dividend yield	**5.28%**
Expected volatility	**25%**

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A summary of stock option activity for the nine months ended September 30, 2012, and information related to outstanding and exercisable stock options at September 30, 2012, is presented below:

	Stock Options		Weighted-Average Exercise Price Per Share	Weighted-Average Remaining Contractual Life (in Years)		Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2011	2,953,630	$	48.09			
Granted	**279,535**		**53.24**			
Exercised	**(1,159,757)**		**47.30**			
Forfeited	**(2,417)**		**53.24**			
Outstanding at September 30, 2012	**2,070,991**	**$**	**49.23**	**6.06**	**$**	**8.4**
Exercisable at September 30, 2012	**1,267,935**	**$**	**50.35**	**4.76**	**$**	**4.3**

The aggregate intrinsic value for outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they all exercised their options at September 30, 2012. This is calculated as the difference between our closing stock price on September 30, 2012, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the nine months ended September 30, 2012, and 2011, was $10.8 million and $1.1 million, respectively. The actual tax benefit realized for the tax deductions from these option exercises was $4.4 million for the nine months ended September 30, 2012 and was not significant for the nine months ended September 30, 2011.

As of September 30, 2012, $1.5 million of compensation cost related to unvested and outstanding stock options was expected to be recognized over a weighted-average period of 2.0 years.

Performance Stock Rights

The fair values of performance stock rights were estimated using a Monte Carlo valuation model. The risk-free interest rate is based on the United States Treasury yield curve. The expected dividend yield incorporates the current and historical dividend rate. The expected volatility was estimated using one to three years of historical data. The table below reflects the assumptions used in the valuation of the outstanding grants at September 30:

	2012
Risk-free interest rate	**0.32% - 1.27%**
Expected dividend yield	**5.28% - 5.34%**
Expected volatility	**21% - 36%**

A summary of the activity for the nine months ended September 30, 2012, related to performance stock rights accounted for as equity awards is presented below:

	Performance Stock Rights		Weighted-Average Fair Value(2)
Outstanding at December 31, 2011	135,948	$	46.18
Granted	**18,865**		**52.70**
Award modifications (1)	**49,304**		**79.62**
Distributed	**(70,598)**		**42.93**
Adjustment for final payout	**(24,804)**		**42.93**
Forfeited	**(163)**		**52.70**
Outstanding at September 30, 2012	**108,552**		**65.35**

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

(2) Reflects the weighted-average fair value used to measure equity awards. Equity awards are measured using the grant date fair value or the fair value on the modification date.

The weighted-average grant date fair value of performance stock rights awarded during the nine months ended September 30, 2012, and 2011, was $52.70 and $49.21, per performance stock right, respectively.

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A summary of the activity for the nine months ended September 30, 2012, related to performance stock rights accounted for as liability awards is presented below:

	Performance Stock Rights
Outstanding at December 31, 2011	186,215
Granted	**75,408**
Award modifications*	**(49,304)**
Distributed	**(16,001)**
Adjustment for final payout	**(5,622)**
Forfeited	**(652)**
Outstanding at September 30, 2012	**190,044**

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

The weighted-average fair value of all outstanding performance stock rights accounted for as liability awards as of September 30, 2012, was $54.53 per performance stock right.

As of September 30, 2012, $2.9 million of compensation cost related to unvested and outstanding performance stock rights (equity and liability awards) was expected to be recognized over a weighted-average period of 1.3 years.

The total intrinsic value of performance stock rights distributed during the nine months ended September 30, 2012, and 2011, was $4.7 million and $6.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights during the nine months ended September 30, 2012, and 2011, was $1.9 million and $2.5 million, respectively.

Restricted Shares and Restricted Share Units

During the second quarter of 2011, the last of the outstanding restricted shares vested. Only restricted share units remain outstanding at September 30, 2012.

A summary of the activity related to all restricted share unit awards (equity and liability awards) for the nine months ended September 30, 2012, is presented below:

	Restricted Share Unit Awards	Weighted-Average Grant Date Fair Value
Outstanding at December 31, 2011	497,722	$ 45.21
Granted	**188,346**	**53.24**
Dividend equivalents	**19,209**	**48.22**
Vested and released	**(196,491)**	**45.12**
Forfeited	**(3,095)**	**49.10**
Outstanding at September 30, 2012	**505,691**	**48.38**

As of September 30, 2012, $12.0 million of compensation cost related to these awards was expected to be recognized over a weighted-average period of 2.4 years.

The total intrinsic value of restricted share and restricted share unit awards vested and released during the nine months ended September 30, 2012, and 2011, was $10.5 million and $6.6 million, respectively. The actual tax benefit realized for the tax deductions from the vesting and release of restricted shares and restricted share units during the nine months ended September 30, 2012, and 2011, was $4.2 million and $2.6 million, respectively.

The weighted-average grant date fair value of restricted share units awarded during the nine months ended September 30, 2012, and 2011, was $53.24 and $49.39 per share, respectively.

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NOTE 16 COMMON EQUITY

We had no changes to issued common stock during the nine months ended September 30, 2012.

Beginning May 1, 2011, 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.

The following table reconciles common shares issued and outstanding:

	September 30, 2012		December 31, 2011	
	Shares	**Average Cost**	**Shares**	**Average Cost**
Common stock issued	**78,287,906**		78,287,906	
Less:				
Deferred compensation rabbi trust	**380,636**	**$ 45.94***	382,971	$ 44.54*
Total common shares outstanding	**77,907,270**		77,904,935	

* Based on our stock price on the day the shares entered the deferred compensation rabbi trust. Shares paid out of the trust are valued at the average cost of shares in the trust.

Earnings Per Share

Basic earnings per share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for shares we are obligated to issue under the deferred compensation and restricted share unit plans. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive items include in-the-money stock options, performance stock rights, restricted share units, and certain shares issuable under the deferred compensation plan. The calculations of diluted earnings per share for the three months ended September 30, 2012, and 2011, excluded 0.9 million and 0.8 million, respectively, out-of-the-money stock options that had an anti-dilutive effect. The calculations of diluted earnings per share for the nine months ended September 30, 2012, and 2011, excluded 0.6 million and 0.8 million, respectively, out-of-the-money stock options that had an anti-dilutive effect. The following table reconciles our computation of basic and diluted earnings per share:

	Three Months Ended September 30		Nine Months Ended September 30	
(Millions, except per share amounts)	**2012**	**2011**	**2012**	**2011**
Numerator:				
Net income from continuing operations	**$ 74.2**	$ 37.4	**$ 224.3**	$ 193.9
Discontinued operations, net of tax	**(7.9)**	0.2	**(8.7)**	(2.9)

Preferred stock dividends of subsidiary		**(0.7)**		(0.7)		**(2.3)**		(2.3)
Noncontrolling interest in subsidiaries		**0.1**				**0.1**		
Net income attributed to common shareholders	**$**	**65.7**	$	36.9	**$**	**213.4**	$	188.7
Denominator:								
Average shares of common stock basic		**78.5**		78.7		**78.5**		78.6
Effect of dilutive securities								
Stock-based compensation		**0.6**		0.5		**0.6**		0.3
Deferred compensation		**0.2**				**0.2**		
Average shares of common stock diluted		**79.3**		79.2		**79.3**		78.9
Earnings per common share								
Basic	**$**	**0.84**	$	0.47	**$**	**2.72**	$	2.40
Diluted		**0.83**		0.47		**2.69**		2.39

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Accumulated Other Comprehensive Loss

The following table shows the changes to our accumulated other comprehensive loss from December 31, 2011 to September 30, 2012:

	Cash Flow Hedges	Defined Benefit Pension Plans	Accumulated Other Comprehensive Income (Loss)
Beginning balance at December 31, 2011	$ (11.5)	$ (31.0)	$ (42.5)
Current period other comprehensive income	**4.0**	**1.1**	**5.1**
Ending balance at September 30, 2012	**$ (7.5)**	**$ (29.9)**	**$ (37.4)**

Dividend Restrictions

Our ability as a holding company to pay dividends is largely dependent upon the availability of funds from our subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. Our regulated utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly.

The PSCW allows WPS to pay dividends on its common stock of no more than 103% of the previous year s common stock dividend. WPS may return capital to us if its average financial common equity ratio is at least 50.24% on a calendar-year basis. WPS must obtain PSCW approval if a return of capital would cause its average financial common equity ratio to fall below this level. Our right to receive dividends on the common stock of WPS is also subject to the prior rights of WPS s preferred shareholders and to provisions in WPS s restated articles of incorporation, which limit the amount of common stock dividends that WPS may pay if its common stock and common stock surplus accounts constitute less than 25% of its total capitalization.

NSG s long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

PGL and WPS have short-term debt obligations containing financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of their outstanding debt obligations.

We also have short-term and long-term debt obligations that contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default which could result in the acceleration of outstanding debt obligations. At September 30, 2012, these covenants did not restrict the payment of any dividends beyond the amount restricted under our subsidiary requirements described above.

As of September 30, 2012, total restricted net assets were $1,480.4 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $121.0 million at September 30, 2012.

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

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

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Capital Transactions with Subsidiaries

During the nine months ended September 30, 2012, capital transactions with subsidiaries were as follows (in millions):

Subsidiary	Dividends To Parent	Return Of Capital To Parent	Equity Contributions From Parent
WPS	$ **79.1**	$ **50.0**	$ **40.0**
WPS Investments, LLC (1)	**50.8**		**17.0**
PGL (2)	**55.0**		
NSG (2)	**10.0**		
MERC		**18.0**	**11.0**
IBS		**23.0**	**10.0**
MGU		**6.0**	
UPPCO		**11.5**	**8.5**
Total	$ **194.9**	$ **108.5**	$ **86.5**

(1) WPS Investments, LLC is a consolidated subsidiary that is jointly owned by us, WPS, and UPPCO. At September 30, 2012, we had an 85.70% ownership interest, while WPS and UPPCO had an 11.79% and 2.51% ownership interest, respectively. Distributions from WPS Investments, LLC are made to the owners based on their respective ownership percentages. During 2012, all equity contributions to WPS Investments, LLC were made solely by us.

(2) PGL and NSG are direct wholly owned subsidiaries of PELLC. As a result, they make distributions to PELLC, and receive equity contributions from PELLC. Subject to applicable law, PELLC does not have any dividend restrictions or limitations on distributions to us.

NOTE 17 VARIABLE INTEREST ENTITIES

In 2012, ITF formed AMP Trillium LLC as a joint venture with AMP Americas LLC. ITF owns 30% and AMP Americas LLC owns 70% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture will be loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At September 30, 2012, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of AMP Trillium LLC assets and liabilities included on our September 30, 2012, balance sheet were also not significant.

In 2011, ITF formed Integrys PTI CNG Fuels LLC as a joint venture with Paper Transport Inc. ITF and Paper Transport Inc. each own 50% of the joint venture. The joint venture was established to own and operate compressed natural gas fueling stations. The preferred source of capital funding for the joint venture will be loans from ITF. We determined that the joint venture is a variable interest entity and that ITF is the primary beneficiary, which requires us to consolidate the assets, liabilities, and statements of income of the joint venture. At September 30, 2012, and December 31, 2011, our variable interests in the joint venture included an insignificant equity investment and insignificant receivables. Our maximum exposure to loss as a result of this joint venture was not significant. The carrying amounts of Integrys PTI CNG Fuels LLC assets and liabilities included on our balance sheets were not significant.

We have variable interests in two entities through power purchase agreements relating to the cost of fuel. One of these agreements reimburses an independent power producing entity for coal costs relating to purchased energy. There is no obligation to purchase energy under the agreement. This contract for 17.5 megawatts of capacity expires in 2014. The other agreement contains a 500-megawatt tolling arrangement in which we supply the scheduled fuel and purchase capacity and energy from the facility. In connection with the pending purchase of Fox Energy Company LLC, WPS will pay $50.0 million to terminate this tolling arrangement. See Note 4, *Agreement to Purchase Fox Energy Center*, for more information regarding this pending purchase. As of September 30, 2012, and December 31, 2011, we had a total of 517.5 megawatts of capacity available under these agreements. We evaluated both of these variable interest entities for possible consolidation. We considered which interest holder has the power to direct the activities that most significantly impact the economics of the variable interest entity; this interest holder is considered the primary beneficiary of the entity and is required to consolidate the entity. For a variety of reasons, including qualitative factors such as the length of the remaining term of the contracts compared with the remaining lives of the plants and the fact that we do not have the power to direct the operations and maintenance of the facilities, we determined we are not the primary beneficiary of these variable interest entities. At September 30, 2012, and December 31, 2011, the assets and liabilities on the balance sheets that related to our involvement with these variable interest entities pertained to working capital accounts and represented the amounts we owed for current deliveries of power. We have not guaranteed any debt or provided any equity support, liquidity arrangements, performance guarantees, or other commitments associated with these contracts. There is not a significant potential exposure to loss as a result of involvement with the variable interest entities.

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NOTE 18 FAIR VALUE

Fair Value Measurements

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

	September 30, 2012			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	**$ 4.5**	**$ 6.6**	**$**	**$ 11.1**
Financial transmission rights (FTRs)			**3.4**	**3.4**
Petroleum product contracts	**0.3**			**0.3**
Nonregulated Segments				
Natural gas contracts	**23.5**	**58.7**	**4.1**	**86.3**
Electric contracts	**37.8**	**57.1**	**5.0**	**99.9**
Foreign exchange contracts		**0.1**		**0.1**
Total Risk Management Assets	**$ 66.1**	**$ 122.5**	**$ 12.5**	**$ 201.1**
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	**$ 0.2**	**$ 18.7**	**$**	**$ 18.9**
FTRs			**0.2**	**0.2**
Coal contract			**9.3**	**9.3**
Nonregulated Segments				
Natural gas contracts	**35.7**	**41.2**	**1.7**	**78.6**
Electric contracts	**47.4**	**85.4**	**14.3**	**147.1**
Foreign exchange contracts	**0.1**			**0.1**
Total Risk Management Liabilities	**$ 83.4**	**$ 145.3**	**$ 25.5**	**$ 254.2**

	December 31, 2011			
(Millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Risk Management Assets				
Utility Segments				
Natural gas contracts	$ 0.1	$ 9.1	$	$ 9.2
FTRs			2.3	2.3
Petroleum product contracts	0.1			0.1
Nonregulated Segments				
Natural gas contracts	50.7	104.1	8.7	163.5
Electric contracts	41.2	71.2	3.9	116.3
Foreign exchange contracts		0.2		0.2
Total Risk Management Assets	$ 92.1	$ 184.6	$ 14.9	$ 291.6
Risk Management Liabilities				
Utility Segments				
Natural gas contracts	$ 5.5	$ 39.2	$	$ 44.7
FTRs			0.1	0.1

Coal contract						6.9		6.9
Nonregulated Segments								
Natural gas contracts		55.0		105.6		0.4		161.0
Electric contracts		54.2		131.1		15.4		200.7
Foreign exchange contracts		0.2						0.2
Total Risk Management Liabilities	$	114.9	$	275.9	$	22.8	$	413.6

The risk management assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. See Note 3, *Risk Management Activities*, for more information on derivative instruments.

The tables above include amounts that were classified as held for sale at Integrys Energy Services. The carrying value of our assets and liabilities from risk management activities that were classified as held for sale is shown in the table below. See Note 5, *Discontinued Operations*, for more information.

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(Millions)		September 30, 2012	December 31, 2011
Risk Management Assets			
Nonregulated Segments			
Electric contracts	Level 2	**$ 0.1**	$
Risk Management Liabilities			
Nonregulated Segments			
Electric contracts	Level 2	**0.1**	0.1

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

Nonregulated Segments Electric Contracts

	Three Months Ended September 30, 2012			Three Months Ended September 30, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**(1.9)**	$	N/A	0.7
Transfers into Level 3 from		**1.0**	**N/A**		(1.5)	N/A

Nonregulated Segments Electric Contracts

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$ (1.6)
Transfers into Level 2 from	**$**	**N/A**	**(5.8)**	$	N/A	(6.1)
Transfers into Level 3 from		**(7.8)**	**N/A**		(6.8)	N/A

Nonregulated Segments Natural Gas Contracts

	Three Months Ended September 30, 2012			Three Months Ended September 30, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$
Transfers into Level 2 from	**$**	**N/A**	**0.3**	$	N/A	0.1
Transfers into Level 3 from		**0.4**	**N/A**		0.2	N/A

Nonregulated Segments Natural Gas Contracts

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
(Millions)	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
Transfers into Level 1 from	**N/A**	**$**	**$**	N/A	$	$

Transfers into Level 2 from	**$**	**N/A**	**1.7**	$	N/A	0.7
Transfers into Level 3 from		**3.2**	**N/A**		0.2	N/A

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

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.

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

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

We have established risk oversight committees whose primary responsibility includes directly or indirectly ensuring that all valuation methods are applied in accordance with predefined policies. The development and maintenance of our forward price curves has been assigned to our risk management department, which is part of the corporate treasury function. This group is separate and distinct from any of the trading functions within the organization. To validate the reasonableness of our fair value inputs, our risk management department compares changes in valuation and researches any significant differences in order to determine the underlying cause. Corrections to the fair value inputs are made if necessary.

The significant unobservable inputs used in the valuation that resulted in categorization within Level 3 were as follows at September 30, 2012. The amounts and percentages listed in the table below represent the range of unobservable inputs that individually had a significant impact on the fair value determination and caused a derivative transaction to be classified as Level 3.

	Fair Value (Millions)					
	Assets	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Average or Range**	
Utility Segments						
FTRs	$ 3.4	$ 0.2	Market-based	Forward market prices ($/megawatt-month) (1)	175.25	
Coal contract		9.3	Market-based	Forward market prices ($/ton) (2)	14.75	16.20
Nonregulated Segments						
Natural gas contracts	86.3	78.6	Market-based	Forward market prices ($/dekatherm) (3)	(0.03)	2.17
				Probability of default	11.62%	50.99%
Electric contracts	99.9	147.1	Market-based	Forward market prices ($/megawatt-hours) (3)	(4.40)	46.98
				Option volatilities (4)	21.20%	54.47%
				Monthly curve shaping (5)	(61.70)%	29.63%

(1) Represents forward market prices developed using historical cleared pricing data from MISO used in the valuation of FTRs.

(2) Represents third-party forward market pricing used in the valuation of our coal contract.

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

(4) Represents the range of volatilities used in the valuation of options.

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

Significant changes in historical settlement prices, forward commodity prices, and option volatilities would result in a directionally similar significant change in fair value. Significant changes in probability of default would result in a significant directionally opposite change in fair value. Changes in the adjustments to prices related to monthly curve shaping would affect fair value differently depending on their direction.

The following tables set forth a reconciliation of changes in the fair value of items categorized as Level 3 measurements:

Three Months Ended September 30, 2012	Nonregulated Segments		Utility Segments		
(Millions)	Natural Gas	Electric	FTRs	Coal Contract	Total
Balance at the beginning of the period	$ 6.3	$ (14.7)	$ 4.8	$ (9.8)	$ (13.4)
Net realized and unrealized gains (losses) included in earnings	2.7	2.6*	(1.0)		4.3
Net unrealized (losses) gains recorded as regulatory assets or liabilities			(0.2)	2.1	1.9
Settlements	(6.7)	(0.1)	(0.4)	(1.6)	(8.8)
Net transfers into Level 3	0.4	1.0			1.4
Net transfers out of Level 3	(0.3)	1.9			1.6
Balance at the end of the period	$ 2.4	$ (9.3)	$ 3.2	$ (9.3)	$ (13.0)
Net unrealized gains included in earnings related to instruments still held at the end of the period	$ 2.7	$ 2.6*	$	$	$ 5.3

* Includes a $0.2 million net unrealized loss reported as discontinued operations. See Note 5, *Discontinued Operations,* for more information.

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Nine Months Ended September 30, 2012	**Nonregulated Segments**		**Utility Segments**		
(Millions)	**Natural Gas**	**Electric**	**FTRs**	**Coal Contract**	**Total**
Balance at the beginning of the period	**$ 8.3**	**$ (11.5)**	**$ 2.2**	**$ (6.9)**	**$ (7.9)**
Net realized and unrealized gains (losses) included in earnings	**1.9**	**(5.3)****	**1.5**		**(1.9)**
Net unrealized gains recorded as regulatory assets or liabilities			**0.1**	**1.5**	**1.6**
Purchases		**2.1**	**4.9**		**7.0**
Sales			**(0.1)**		**(0.1)**
Settlements	**(9.3)**	**7.4**	**(5.4)**	**(3.9)**	**(11.2)**
Net transfers into Level 3	**3.2**	**(7.8)**			**(4.6)**
Net transfers out of Level 3	**(1.7)**	**5.8**			**4.1**
Balance at the end of the period	**$ 2.4**	**$ (9.3)**	**$ 3.2**	**$ (9.3)**	**$ (13.0)**
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	**$ 1.9**	**$ (5.3)***	**$ —**	**$ —**	**$ (3.4)**

* Includes a $0.6 million net unrealized loss reported as discontinued operations. See Note 5, *Discontinued Operations,* for more information.

Three Months Ended September 30, 2011	**Nonregulated Segments**		**Utility Segments**		
(Millions)	**Natural Gas**	**Electric**	**FTRs**	**Coal Contract**	**Total**
Balance at the beginning of the period	$ 16.1	$ (9.3)	$ 5.5	$ (4.3)	$ 8.0
Net realized and unrealized gains (losses) included in earnings	7.9	1.5*	(0.2)		9.2
Net unrealized (losses) gains recorded as regulatory assets or liabilities			(0.1)	4.2	4.1
Purchases		(0.1)			(0.1)
Settlements	(4.1)	0.9	(1.5)	(0.4)	(5.1)
Net transfers into Level 3	0.2	(1.5)			(1.3)
Net transfers out of Level 3	(0.1)	(0.7)			(0.8)
Balance at the end of the period	$ 20.0	$ (9.2)	$ 3.7	$ (0.5)	$ 14.0
Net unrealized gains included in earnings related to instruments still held at the end of the period	$ 7.9	$ 1.5*	$ —	$ —	$ 9.4

* Includes a $0.3 million net unrealized gain reported as discontinued operations. See Note 5, *Discontinued Operations,* for more information.

Nine Months Ended September 30, 2011	**Nonregulated Segments**		**Utility Segments**		
(Millions)	**Natural Gas**	**Electric**	**FTRs**	**Coal Contract**	**Total**
Balance at the beginning of the period	$ 30.2	$ (14.9)	$ 2.9	$ 2.5	$ 20.7
Net realized and unrealized gains (losses) included in earnings	15.6	(2.3)*	(1.3)		12.0
Net unrealized losses recorded as regulatory assets or liabilities			(1.7)	(1.7)	(3.4)
Net unrealized gains included in other comprehensive loss		0.6			0.6
Purchases		1.8	5.9		7.7
Sales			(0.1)		(0.1)

Settlements		(25.3)		4.7		(2.0)		(1.3)		(23.9)
Net transfers into Level 3		0.2		(6.8)						(6.6)
Net transfers out of Level 3		(0.7)		7.7						7.0
Balance at the end of the period	$	20.0	$	(9.2)	$	3.7	$	(0.5)	$	14.0
Net unrealized gains (losses) included in earnings related to instruments still held at the end of the period	$	15.6	$	(2.3)*	$		$		$	13.3

* Includes a $0.5 million net unrealized gain reported as discontinued operations. See Note 5, *Discontinued Operations,* for more information.

Unrealized gains and losses included in earnings related to Integrys Energy Services risk management assets and liabilities are recorded through nonregulated revenue on the statements of income. Realized gains and losses on these same instruments are recorded in nonregulated revenue

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or nonregulated cost of sales, depending on the nature of the instrument. Unrealized gains and losses on Level 3 derivatives at the utilities are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through utility cost of fuel, natural gas, and purchased power on the statements of income.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value:

	September 30, 2012		**December 31, 2011**	
(Millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt *	**$ 2,122.1**	**$ 2,291.7**	$ 2,122.0	$ 2,281.5
Preferred stock	**51.1**	**52.6**	51.1	51.8

* Includes a $27.0 million loan included in liabilities held for sale on our balance sheets related to the pending sale of WPS Westwood Generation, LLC. See Note 5, *Discontinued Operations,* and Note 10, *Long-term Debt,* for more information

The fair values of long-term debt instruments are estimated based on the quoted market price for the same or similar issues, or on the current rates offered to us for debt of the same remaining maturity, without considering the effect of third-party credit enhancements. The fair values of preferred stock are estimated based on quoted market prices when available, or by using a perpetual dividend discount model. The fair values of long-term debt instruments and preferred stock are categorized within Level 2 of the fair value hierarchy.

Due to the short-term nature of cash and cash equivalents, accounts receivable, accounts payable, notes payable, and outstanding commercial paper, the carrying amount for each such item approximates fair value.

NOTE 19 ADVERTISING COSTS

Costs associated with certain natural gas and electric direct-response advertising campaigns at Integrys Energy Services were capitalized and reported as other long-term assets on the balance sheets. The capitalized costs result in probable future benefits and were incurred to solicit sales to customers who could be shown to have responded specifically to the advertising. Capitalized direct-response advertising costs, net of accumulated amortization, totaled $5.4 million and $3.4 million as of September 30, 2012, and December 31, 2011, respectively. The asset balances for each of the direct-response advertising cost pools are reviewed quarterly for impairment, and there was no impairment during the periods ended September 30, 2012 and 2011.

Direct-response advertising costs are amortized to operating and maintenance expense over the estimated period of benefit, which is approximately two years. The amortization of direct-response advertising costs was $1.0 million and $0.4 million for the three months ended September 30, 2012 and 2011, respectively. The amortization of direct-response advertising costs was $2.3 million and $0.4 million for the nine months ended September 30, 2012 and 2011, respectively.

We expense all advertising costs as incurred, except for those capitalized as direct-response advertising, as discussed above. Other advertising expense was $2.1 million and $2.3 million for the three months ended September 30, 2012 and 2011, respectively. Other advertising expense was $5.2 million and $6.1 million for the nine months ended September 30, 2012 and 2011, respectively.

NOTE 20 REGULATORY ENVIRONMENT

Wisconsin

2013 Rates

On March 30, 2012, WPS filed an application with the PSCW to increase retail electric and natural gas rates $85.1 million and $12.8 million, respectively, with rates proposed to be effective January 1, 2013. The filing included a request for a 10.30% return on common equity and a common equity ratio of 52.37% in WPS s regulatory capital structure. On October 3, 2012, WPS filed a proposed settlement agreement with the PSCW reflecting the results of the PSCW staff audit and more current information. On October 24, 2012, the PSCW verbally approved the settlement agreement. The settlement agreement, updated as of November 2012 for changes in certain costs, includes a $28.5 million retail electric rate increase, which will be offset by the 2012 fuel refund. The settlement agreement reflects an estimated 2012 fuel refund of $19.2 million. Any difference between the actual 2012 fuel refund and the rate increase will be deferred for recovery in a future rate proceeding. As a result, there will be no change to customers 2013 retail electric rates. The updated agreement also includes a $0.9 million retail natural gas rate decrease. The updated settlement agreement reflects a 10.30% return on common equity and a common equity ratio of 51.61% in WPS s regulatory capital structure. Decoupling was approved on a pilot basis for 2013. The decoupling mechanism will be based on total rate case-approved margins, rather than being calculated on a per-customer basis. It will continue to include an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. In addition, WPS was authorized recovery of $5.9 million related to income tax amounts previously expensed due to the Federal Health Care Reform Act. As a result, this amount was recorded as a regulatory asset at September 30, 2012. The settlement agreement also authorized the recovery of direct CSAPR costs incurred through the end of 2012. As of September 30, 2012, WPS deferred $3.2 million of costs related to CSAPR. WPS expects a final written order from the PSCW before the end of 2012.

2012 Rates

On December 9, 2011, the PSCW issued a final written order for WPS, effective January 1, 2012. It authorized an electric rate increase of $8.1 million and required a natural gas rate decrease of $7.2 million. The electric rate increase was driven by projected increases in fuel and purchased power costs. However, to the extent that actual fuel and purchased power costs exceed a 2% price variance from costs included in rates, they will be deferred for recovery or refund in a future rate proceeding. The rate order allows for the netting of the 2010 electric decoupling under-collection with the 2011 electric decoupling over-collection, and reflects reduced contributions to the Focus on Energy Program. The rate order also allows for the deferral of direct Cross State Air Pollution Rule (CSAPR) compliance costs, including carrying costs.

2011 Rates

On January 13, 2011, the PSCW issued a final written order for WPS authorizing an electric rate increase of $21.0 million, calculated on a per-unit basis. Although the 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 rate order also included a projected increase in customer counts that did not materialize, which impacts the decoupling calculation as it adjusts for differences between the actual and authorized margin per customer. The $21.0 million electric rate increase included $20.0 million of recovery of prior deferrals, the majority of which related to the recovery of the 2009 electric decoupling deferral. The $21.0 million excluded the impact of a $15.2 million estimated fuel refund (including carrying costs) from 2010. The PSCW rate order also required an $8.3 million decrease in natural gas rates, which included $7.1 million of recovery for the 2009 decoupling deferral. The new rates were effective January 14, 2011, and reflected a 10.30% return on common equity, down from a 10.90% return on common equity in the previous rate order, and a common equity ratio of 51.65% in WPS s regulatory capital structure.

The order also addressed the new Wisconsin electric fuel rule, which was finalized on March 1, 2011. The new fuel rule was effective retroactive to January 1, 2011. It requires the deferral of under or over-collections of fuel and purchased power costs that exceed a 2% price variance from the cost of fuel and purchased power included in rates. Under or over-collections deferred in the current year will be recovered or refunded in a future rate proceeding.

Michigan

2012 UPPCO Rates

On December 20, 2011, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $4.2 million, effective January 1, 2012. The new rates reflect a 10.20% return on common equity and a common equity ratio of 54.90% in UPPCO s regulatory capital structure. The settlement agreement states that if UPPCO files a rate case in 2013, the earliest effective date for new final rates or self-implemented rates is January 1, 2014. Additionally, the settlement required UPPCO to terminate its existing decoupling mechanism, effective December 31, 2011, and replace it with a new decoupling mechanism that will not cover variations in volumes due to weather, beginning January 1, 2013. As a result, UPPCO has no decoupling mechanism in place for 2012.

In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. This decision was not appealed. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. However, on August 14, 2012, the MPSC issued an order stating it had the authority to approve UPPCO s decoupling mechanism, as UPPCO s decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement. Therefore, in the third quarter of 2012, UPPCO reversed the $1.5 million previously expensed in the first quarter of 2012.

2011 UPPCO Rates

On December 21, 2010, the MPSC issued an order approving a settlement agreement for UPPCO authorizing a retail electric rate increase of $8.9 million, effective January 1, 2011. The new rates reflected a 10.30% return on common equity and a common equity ratio of 54.86% in UPPCO s regulatory capital structure. The order required UPPCO to terminate its uncollectibles expense tracking mechanism after the close of December 2010 business, but retained the decoupling mechanism.

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Illinois

2013 Rate Cases

On July 31, 2012, PGL and NSG filed applications with the ICC to increase retail natural gas rates $78.3 million and $9.8 million, respectively, with rates expected to be effective in July 2013. Both PGL s and NSG s requests reflect a 10.75% return on common equity and a target common equity ratio of 50.00% in their regulatory capital structures. On October 23, 2012, PGL and NSG filed supplemental direct testimony revising their requested natural gas rate increases to $102.7 million and $12.5 million, respectively. The revised requests are primarily driven by increased costs due to new permitting and restoration requirements, as well as modifications in natural gas main and service pipe installation procedures.

2012 Rates

On January 10, 2012, the ICC issued a final order authorizing a retail natural gas rate increase of $57.8 million for PGL and $1.9 million for NSG, effective January 21, 2012. The rates for PGL reflect a 9.45% return on common equity and a common equity ratio of 49.00% in PGL s regulatory capital structure. The rates for NSG reflect a 9.45% return on common equity and a common equity ratio of 50.00% in NSG s regulatory capital structure. The rate order also approved a permanent decoupling mechanism.

The Illinois Attorney General appealed the ICC s approval of decoupling and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. On May 16, 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General s motion to make revenues collected under the permanent decoupling mechanism subject to refund. Refunds would be required if the Illinois Appellate Court (Court) finds that the ICC did not have the authority to approve decoupling and the Court orders a refund. As a result, the recovery of amounts related to decoupling is uncertain. Therefore, PGL and NSG reduced revenues by $13.2 million in the second quarter of 2012 related to decoupling amounts accrued for regulatory recovery as of March 31, 2012. These amounts and decoupling amounts accrued thereafter have a reserve established against them equal to the amount accrued. As of September 30, 2012, a reserve of $14.9 million was recorded. PGL and NSG plan to defend the authority of the ICC to approve the decoupling mechanism. PGL and NSG still intend to file with the ICC for rate recovery, beginning in 2013, for amounts accrued related to decoupling since the decoupling mechanism is still in place.

Rider ICR

On January 21, 2010, the ICC approved a rider mechanism for PGL to earn a return on and recover the costs, above an annual baseline, of the AMRP through a special charge on customers bills, known as Rider ICR. The AMRP is a 20-year project that began in 2011 under which PGL is replacing its cast iron and ductile iron pipes with steel and polyethylene pipes. In June 2010, the ICC issued a rehearing order approving PGL s proposed baseline of $45.28 million with an annual escalation factor. Recovery of costs for the AMRP became effective on April 1, 2011. On September 30, 2011, the Illinois Appellate Court, First District, reversed the ICC s approval of Rider ICR, concluding it was improper single issue ratemaking. PGL and the ICC filed for leave to appeal with the Illinois Supreme Court, but their requests were denied. In March 2012, the Illinois Appellate Court remanded the matter to the ICC for further proceeding consistent with its September 30, 2011 decision. On June 27, 2012, the ICC issued a remand order requiring that PGL refund $2.3 million, over a nine-month period beginning in July 2012, in the form of a refund and reconciliation adjustment. A refund amount of $1.9 million was included in PGL s regulatory liabilities as of September 30, 2012.

Minnesota

2011 Rates

On July 13, 2012, the MPUC approved a written order for MERC authorizing a retail natural gas rate increase of $11.0 million, which is expected to become effective in December 2012. The new rates reflect a 9.70% return on common equity and a common equity ratio of 50.48% in MERC s regulatory capital structure. In addition, the order set recovery of MERC s 2011 test-year pension expense at 2010 levels. MERC requested reconsideration of certain aspects of the rate order, including the pension expense, but the request was denied. The MPUC also approved a decoupling mechanism for MERC on a three-year trial basis. The decoupling mechanism becomes effective when final rates are implemented.

Federal

Through a series of orders issued by the FERC, Regional Through and Out Rates for transmission service between the MISO and the PJM Interconnection were eliminated effective December 1, 2004. To compensate transmission owners for the revenue they would no longer receive due to this rate elimination, the FERC ordered a transitional pricing mechanism called the Seams Elimination Charge Adjustment (SECA) be put into place. Load-serving entities paid these SECA charges during a 16-month transition period from December 1, 2004, through March 31, 2006.

Integrys Energy Services initially expensed the majority of the total $19.2 million of billings received for the 16-month transitional period. The remaining amount was considered probable of recovery due to inconsistencies between the FERC s SECA order and the transmission owners

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FERC-ordered compliance filings. Integrys Energy Services protested the FERC s SECA order, and in August 2006, the Administrative Law Judge hearing the case issued an Initial Decision that was in substantial agreement with all of Integrys Energy Services positions. In May 2010, the FERC ruled favorably for Integrys Energy Services on two issues, but reversed the rulings of the Initial Decision on nearly every other substantive issue. Integrys Energy Services and numerous other parties filed for rehearing of the FERC s order on the Initial Decision, which the FERC denied on September 30, 2011. The FERC has not yet issued an order on the compliance filings made by the transmission owners. Integrys Energy Services has appealed the adverse FERC decision to the U.S. Court of Appeals for the D.C. Circuit.

As of September 30, 2012, Integrys Energy Services expected to receive future refunds of $3.8 million. Once the order on compliance filings is issued, refunds will be made. Any refunds will include interest for the period from payment to refund.

NOTE 21 SEGMENTS OF BUSINESS

At September 30, 2012, we reported five segments, which are described below.

- The natural gas utility segment includes the regulated natural gas utility operations of MERC, MGU, NSG, PGL, and WPS.
- The electric utility segment includes the regulated electric utility operations of UPPCO and WPS.
- The electric transmission investment segment includes our approximate 34% ownership interest in ATC. ATC is a federally regulated electric transmission company with operations in Wisconsin, Michigan, Minnesota, and Illinois.
- 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.
- The holding company and other segment includes the operations of the Integrys Energy Group holding company and the PELLC holding company, along with any nonutility activities at IBS, MERC, MGU, NSG, PGL, UPPCO, and WPS. The operations of ITF were included in this segment beginning on September 1, 2011, when we acquired Trillium USA and Pinnacle CNG Systems.

The tables below present information related to our reportable segments:

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	**Natural Gas Utility**	**Electric Utility**	**Electric Transmission Investment**	**Total Regulated Operations**	**Integrys Energy Services**	**Holding Company and Other**	**Reconciling Eliminations**	**Integrys Energy Group Consolidated**
Three Months Ended September 30, 2012								
External revenues	$ 215.5	$ 366.8	$	$ 582.3	$ 335.4	$ 9.9	$	$ 927.6
Intersegment revenues	4.5			4.5	0.1	0.3	(4.9)	
Depreciation and amortization expense	33.2	22.3		55.5	2.7	4.8	(0.1)	62.9
Earnings from equity method investments			21.7	21.7	0.5			22.2
Miscellaneous income	0.1	0.9		1.0	0.3	5.7	(3.9)	3.1
Interest expense	11.7	8.9		20.6	0.5	12.7	(3.9)	29.9

Provision (benefit) for income taxes	**(11.5)**	**19.5**	**8.3**	**16.3**	**15.9**	**(2.8)**	**29.4**
Net income (loss) from continuing operations	**(13.9)**	**47.8**	**13.4**	**47.3**	**32.1**	**(5.2)**	**74.2**
Discontinued operations					**(7.9)**		**(7.9)**
Preferred stock dividends of subsidiary	**(0.1)**	**(0.6)**		**(0.7)**			**(0.7)**
Net income (loss) attributed to common shareholders	**(14.0)**	**47.2**	**13.4**	**46.6**	**24.2**	**(5.1)**	**65.7**

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	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Three Months Ended September 30, 2011								
External revenues	$ 235.0	$ 361.2	$	$ 596.2	$ 332.8	$ 5.4	$	$ 934.4
Intersegment revenues	4.3	6.3		10.6	0.3	0.3	(11.2)	
Depreciation and amortization expense	31.7	22.0		53.7	2.5	5.7	(0.1)	61.8
Earnings (losses) from equity method investments			19.9	19.9	(0.1)	0.1		19.9
Miscellaneous income (expense)	0.2	0.1		0.3	(0.2)	4.8	(3.9)	1.0
Interest expense	11.8	9.4		21.2	0.6	13.4	(3.9)	31.3
Provision (benefit) for income taxes	(13.5)	24.0	7.7	18.2	5.8	(1.5)		22.5
Net income (loss) from continuing operations	(19.9)	40.1	12.2	32.4	10.7	(5.7)		37.4
Discontinued operations					0.2			0.2
Preferred stock dividends of subsidiary	(0.1)	(0.6)		(0.7)				(0.7)
Net income (loss) attributed to common shareholders	(20.0)	39.5	12.2	31.7	10.9	(5.7)		36.9

	Regulated Operations				Nonutility and Nonregulated Operations			
(Millions)	Natural Gas Utility	Electric Utility	Electric Transmission Investment	Total Regulated Operations	Integrys Energy Services	Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Nine Months Ended September 30, 2012								
External revenues	**$ 1,131.3**	**$ 985.6**	**$**	**$ 2,116.9**	**$ 874.0**	**$ 24.6**	**$**	**$ 3,015.5**
Intersegment revenues	**8.1**			**8.1**	**0.6**	**1.5**	**(10.2)**	
Depreciation and amortization expense	**98.3**	**66.4**		**164.7**	**7.5**	**15.9**	**(0.4)**	**187.7**
Earnings from equity method investments			**63.8**	**63.8**	**1.2**	**0.5**		**65.5**
Miscellaneous income	**0.6**	**1.5**		**2.1**	**0.8**	**16.4**	**(12.1)**	**7.2**
Interest expense	**35.1**	**27.1**		**62.2**	**1.5**	**38.4**	**(12.1)**	**90.0**
Provision (benefit) for income taxes	**32.6**	**42.4**	**24.0**	**99.0**	**23.3**	**(16.0)**		**106.3**
Net income (loss) from continuing operations	**53.8**	**94.3**	**39.8**	**187.9**	**45.5**	**(9.1)**		**224.3**
Discontinued operations					**(10.5)**	**1.8**		**(8.7)**
Preferred stock dividends of subsidiary	**(0.4)**	**(1.9)**		**(2.3)**				**(2.3)**
Net income (loss) attributed to common	**53.4**	**92.4**	**39.8**	**185.6**	**35.0**	**(7.2)**		**213.4**

shareholders

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(Millions)	Regulated Operations Natural Gas Utility	Regulated Operations Electric Utility	Regulated Operations Electric Transmission Investment	Total Regulated Operations	Nonutility and Nonregulated Operations Integrys Energy Services	Nonutility and Nonregulated Operations Holding Company and Other	Reconciling Eliminations	Integrys Energy Group Consolidated
Nine Months Ended September 30, 2011								
External revenues	$ 1,447.5	$ 988.2	$	$ 2,435.7	$ 1,117.7	$ 12.4	$	$ 3,565.8
Intersegment revenues	9.2	17.3		26.5	0.7	1.0	(28.2)	
Depreciation and amortization expense	94.2	66.1		160.3	8.0	17.4	(0.4)	185.3
Earnings (losses) from equity method investments			59.0	59.0	(0.1)	0.7		59.6
Miscellaneous income	1.6	0.6		2.2	1.1	16.4	(15.6)	4.1
Interest expense	36.4	33.2		69.6	1.3	42.7	(15.6)	98.0
Provision (benefit) for income taxes	39.6	46.6	23.4	109.6	17.9	(5.8)		121.7
Net income (loss) from continuing operations	58.8	84.7	35.6	179.1	29.7	(14.9)		193.9
Discontinued operations					(2.0)	(0.9)		(2.9)
Preferred stock dividends of subsidiary	(0.4)	(1.9)		(2.3)				(2.3)
Net income (loss) attributed to common shareholders	58.4	82.8	35.6	176.8	27.7	(15.8)		188.7

NOTE 22 NEW ACCOUNTING PRONOUNCEMENTS

Recently Issued Accounting Guidance Not Yet Effective

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. Adoption of this guidance will result in new disclosures in Note 3, *Risk Management Activities,* in the first quarter of 2013.

ASU 2012-02, Testing Indefinite-Lived Intangible Assets for Impairment, was issued in July 2012. The amendments give companies an option to first perform a qualitative assessment to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. If a company concludes that this is the case, the fair value of the indefinite-lived intangible asset must be determined, and a 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, 2013, and is not expected to have a significant impact on our financial statements.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2011.

SUMMARY

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

RESULTS OF OPERATIONS

Earnings Summary

(Millions, except per share amounts)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Change in 2012 Over 2011
Natural gas utility operations	**$ (14.0)**	$ (20.0)	(30.0)%	**$ 53.4**	$ 58.4	(8.6)%
Electric utility operations	**47.2**	39.5	19.5%	**92.4**	82.8	11.6%
Electric transmission investment	**13.4**	12.2	9.8%	**39.8**	35.6	11.8%
Integrys Energy Services operations	**24.2**	10.9	122.0%	**35.0**	27.7	26.4%
Holding company and other operations	**(5.1)**	(5.7)	(10.5)%	**(7.2)**	(15.8)	(54.4)%
Net income attributed to common shareholders	**$ 65.7**	$ 36.9	78.0%	**$ 213.4**	$ 188.7	13.1%
Basic earnings per share	**$ 0.84**	$ 0.47	78.7%	**$ 2.72**	$ 2.40	13.3%
Diluted earnings per share	**$ 0.83**	$ 0.47	76.6%	**$ 2.69**	$ 2.39	12.6%
Average shares of common stock						
Basic	**78.5**	78.7	(0.3)%	**78.5**	78.6	(0.1)%
Diluted	**79.3**	79.2	0.1%	**79.3**	78.9	0.5%

Third Quarter 2012 Compared with Third Quarter 2011

Our 2012 third quarter earnings were $65.7 million, compared with 2011 third quarter earnings of $36.9 million. The $28.8 million increase in earnings was driven by:

- A $20.7 million after-tax non-cash increase in Integrys Energy Services margins related to derivative and inventory fair value adjustments.
- The $7.1 million after-tax positive impact of rate orders at the natural gas utilities, excluding items directly offset in operating expenses.
- A $6.0 million positive quarter-over-quarter impact related to federal health care reform, driven by the reversal in 2012 of $5.9 million of deferred income taxes that had been expensed in prior years due to the implementation of federal health care reform. WPS was authorized recovery of this amount in its 2013 rate case settlement agreement.

These increases were partially offset by an $8.1 million decrease in income from discontinued operations at Integrys Energy Services, primarily related to impairment losses recorded in 2012 related to three generation plants that are held for sale. See Note 5, *Discontinued Operations,* for more information.

Nine Months 2012 Compared with Nine Months 2011

Our earnings were $213.4 million during the nine months ended September 30, 2012, compared with $188.7 million during the same period in 2011. The $24.7 million increase in earnings was driven by:

- The $20.2 million after-tax positive impact of rate orders at the natural gas utilities, excluding items directly offset in operating expenses.
- A $17.1 million after-tax non-cash increase in Integrys Energy Services margins related to derivative and inventory fair value adjustments.

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- A $7.5 million positive period-over-period impact related to federal health care reform, driven by the reversal in 2012 of $5.9 million of deferred income taxes that had been expensed in prior years due to the implementation of federal health care reform. WPS was authorized recovery of this amount in its 2013 rate case settlement agreement.
- A $4.8 million after-tax decrease in interest expense, primarily due to the maturity and repayment of $150 million of long-term debt at WPS in August 2011.
- The $4.4 million net positive period-over-period impact of tax adjustments recorded in 2011 in connection with a change in tax law in Michigan.
- A $4.2 million increase in earnings at the electric transmission investment segment.
- A $4.0 million increase from the remeasurement of unrecognized tax benefit liabilities.

These increases were partially offset by:

- A $22.1 million after-tax decrease in natural gas utility margins due to lower sales volumes driven by warmer weather, net of decoupling.
- An $8.5 million increase in loss from discontinued operations at Integrys Energy Services, primarily related to the impairment losses recorded in 2012 related to three generation plants that are held for sale. See Note 5, *Discontinued Operations,* for more information.
- A $3.1 million after-tax decrease in Integrys Energy Services realized retail electric margins, driven by the expiration of several large, lower margin contracts at the end of 2011, and by competitive pressure on per-unit margins.

Regulated Natural Gas Utility Segment Operations

(Millions, except heating degree days)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Change in 2012 Over 2011
Revenues	**$ 220.0**	$ 239.3	(8.1)%	**$ 1,139.4**	$ 1,456.7	(21.8)%
Purchased natural gas costs	**71.9**	99.6	(27.8)%	**511.1**	811.3	(37.0)%
Margins	**148.1**	139.7	6.0%	**628.3**	645.4	(2.6)%
Operating and maintenance expense	**119.7**	121.1	(1.2)%	**382.0**	391.7	(2.5)%
Depreciation and amortization expense	**33.2**	31.7	4.7%	**98.3**	94.2	4.4%
Taxes other than income taxes	**9.0**	8.7	3.4%	**27.1**	26.3	3.0%
Operating income (loss)	**(13.8)**	(21.8)	(36.7)%	**120.9**	133.2	(9.2)%
Miscellaneous income	**0.1**	0.2	(50.0)%	**0.6**	1.6	(62.5)%
Interest expense	**(11.7)**	(11.8)	(0.8)%	**(35.1)**	(36.4)	(3.6)%
Other expense	**(11.6)**	(11.6)	%	**(34.5)**	(34.8)	(0.9)%
Income (loss) before taxes	**$ (25.4)**	$ (33.4)	(24.0)%	**$ 86.4**	$ 98.4	(12.2)%

Retail throughput in therms						
Residential	**87.2**	95.6	(8.8)%	**864.6**	1,106.6	(21.9)%
Commercial and industrial	**36.3**	37.1	(2.2)%	**270.7**	342.5	(21.0)%
Other	**23.3**	12.0	94.2%	**56.2**	45.7	23.0%
Total retail throughput in therms	**146.8**	144.7	1.5%	**1,191.5**	1,494.8	(20.3)%
Transport throughput in therms						
Residential	**15.8**	16.6	(4.8)%	**134.2**	170.6	(21.3)%
Commercial and industrial	**299.7**	293.2	2.2%	**1,110.7**	1,161.2	(4.3)%
Total transport throughput in therms	**315.5**	309.8	1.8%	**1,244.9**	1,331.8	(6.5)%
Total throughput in therms	**462.3**	454.5	1.7%	**2,436.4**	2,826.6	(13.8)%
Weather						
Average heating degree days	**165**	183	(9.8)%	**3,367**	4,635	(27.4)%

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Third Quarter 2012 Compared with Third Quarter 2011

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 utility revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 30% decrease in the average per-unit cost of natural gas sold during the third quarter of 2012, which had no impact on margins.

Regulated natural gas utility segment margins increased $8.4 million:

- Rate increases at PGL and NSG, effective January 21, 2012, and other impacts of rate design, drove an approximate $10 million net increase in margins. See Note 20, *Regulatory Environment,* for more information.
- Lower sales volumes excluding the impact of weather resulted in a partially offsetting approximate $3 million decrease in margins. Sales volumes were lower due to lower use per residential customer.

Operating Loss

Operating loss at the regulated natural gas utility segment decreased $8.0 million. This decrease was primarily driven by the $8.4 million increase in margins discussed above, partially offset by a $0.4 million increase in operating expenses.

The increase in operating expenses primarily related to:

- A $5.3 million increase in natural gas distribution costs. The increase was partially due to additional costs related to compliance work and increased contractor costs associated with the movement of employees to the AMRP project. Costs associated with permits, restoration, and other miscellaneous distribution costs also contributed to the increase.
- A $1.5 million increase in depreciation and amortization expense. The increase resulted from higher property and equipment balances, primarily driven by the AMRP.
- These increases were substantially offset by:
  - A $2.4 million decrease in bad debt expense, driven by a new cost of gas component included as part of PGL s and NSG s bad debt expense tracking mechanisms. The change in the bad debt mechanisms was approved in PGL s and NSG s most recent rate orders, effective January 21, 2012. As a result of this component, bad debt expense was partially impacted by lower natural gas costs in 2012 and the decrease in volumes discussed above.

- A $2.1 million decrease in energy efficiency program expenses related to WPS s participation in the Focus on Energy Program and MERC s conservation improvement program. Costs for both programs are recovered in rates.
- A $1.0 million decrease in customer accounts expense driven by a decrease in maintenance of a customer billing system and a decrease in labor as a result of fewer customer disconnections.

Nine Months 2012 Compared with Nine Months 2011

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 utility revenues since we pass through prudently incurred natural gas commodity costs to our customers in current rates. There was an approximate 21% decrease in the average per-unit cost of natural gas sold during 2012, which had no impact on margins.

Regulated natural gas utility segment margins decreased $17.1 million, driven by:

- An approximate $37 million net decrease in margins, including the impact of decoupling, due to a 13.8% decrease in volumes sold.
  - Warmer weather during 2012 drove an approximate $64 million decrease in margins. Heating degree days decreased 27.4%.

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- Decoupling impacts at certain natural gas utilities drove an approximate $27 million increase in margins.
  - Decoupling accruals in 2012 had an approximate $9 million positive impact on the period-over-period variance. Decoupling lessened the negative impact from some of the decreased sales volumes at WPS and MGU through higher future recoveries from customers. This was limited by an $8 million decoupling cap that was reached by WPS during the second quarter of 2012. In addition, although decoupling was implemented to minimize the impact of changes in sales volumes, it does not cover all jurisdictions or customer classes.
  - Decoupling accruals in 2011 had an approximate $18 million positive impact on the period-over-period variance. Decoupling lessened the positive impact in 2011 from some of the increased sales volumes at PGL, NSG, WPS, and MGU through higher future refunds to customers.
- An approximate $7 million decrease in margins related to certain riders at PGL and NSG. Higher regulatory refunds and lower regulatory recoveries under these riders are offset by equal decreases in operating expenses, resulting in no impact on earnings.
  - We recovered approximately $6 million less for environmental cleanup costs at our former manufactured gas plant sites in 2012. The lower recovery reflects a pass-through to our customers in rates of an environmental settlement received from a potentially responsible party s performance and payment bond. See Note 12, *Commitment and Contingencies*, for more information about the manufactured gas plant sites.
  - We refunded approximately $2 million more to customers under bad debt riders in 2012.
  - We billed approximately $1 million more to customers for energy efficiency programs in 2012.
- An approximate $2 million decrease in margins due to a rider approved through September 30, 2011 for recovery of AMRP costs at PGL. See Note 20, *Regulatory Environment,* for more information on this rider.
- The decrease in margins was partially offset by an approximate $29 million net increase in margins due to rate orders. See Note 20, *Regulatory Environment,* for more information.
  - The rate increases at PGL and NSG, effective January 21, 2012, and other impacts of rate design, had an approximate $33 million positive impact on margins.
  - A reduction in rates at WPS, effective January 1, 2012, resulted in an approximate $3 million negative impact on margins. The rate decrease was driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions is offset by lower operating expenses.
  - MERC had an approximate $1 million decrease in margins in 2012 driven by the impact of a July 2012 rate order from the MPUC, relative to the impact of 2011 interim rates in effect since February 1, 2011.

Operating Income

Operating income at the regulated natural gas utility segment decreased $12.3 million. This decrease was primarily driven by the $17.1 million decrease in margins discussed above, partially offset by a $4.8 million decrease in operating expenses.

The decrease in operating expenses primarily related to:

- A $7.9 million decrease in energy efficiency program expenses related to WPS s participation in the Focus on Energy Program and MERC s conservation improvement program. Costs for both programs are recovered in rates.

- An approximate $7 million net decrease due to lower amortization of regulatory assets related to environmental cleanup costs for manufactured gas plant sites and higher amortization of regulatory liabilities related to bad debt riders and enhanced efficiency programs, all at PGL and NSG. Margins decreased by an equal amount, resulting in no impact on earnings.

- A $7.0 million decrease in bad debt expense, driven by a new cost of gas component included as part of PGL s and NSG s bad debt expense tracking mechanisms. The change in the bad debt mechanisms was approved in PGL s and NSG s most recent rate orders, effective January 21, 2012. As a result of this component, bad debt expense was partially impacted by lower natural gas costs in 2012 and the decrease in volumes related to warmer weather discussed above.

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- A $4.6 million decrease in employee benefit expenses. The primary driver of the decrease was lower postretirement health care expenses, driven by an increase in plan assets due to contributions to our trust.
- A $1.6 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.
- These decreases were partially offset by:
  - An $18.6 million increase in natural gas distribution costs. The increase was partially due to additional labor related to compliance work and increased contractor costs associated with the movement of employees to the AMRP project. Costs associated with permits, restoration, and other miscellaneous distribution costs also contributed to the increase.
  - A $4.1 million increase in depreciation and amortization expense. The increase resulted from higher property and equipment balances, primarily driven by the AMRP.

Regulated Electric Utility Segment Operations

(Millions, except degree days)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Change in 2012 Over 2011
Revenues	**$ 366.8**	$ 367.5	(0.2)%	**$ 985.6**	$ 1,005.5	(2.0)%
Fuel and purchased power costs	**160.9**	157.5	2.2%	**423.9**	428.9	(1.2)%
Margins	**205.9**	210.0	(2.0)%	**561.7**	576.6	(2.6)%
Operating and maintenance expense	**96.6**	102.7	(5.9)%	**296.7**	310.4	(4.4)%
Depreciation and amortization expense	**22.3**	22.0	1.4%	**66.4**	66.1	0.5%
Taxes other than income taxes	**11.7**	11.9	(1.7)%	**36.3**	36.2	0.3%
Operating income	**75.3**	73.4	2.6%	**162.3**	163.9	(1.0)%
Miscellaneous income	**0.9**	0.1	800.0%	**1.5**	0.6	150.0%
Interest expense	**(8.9)**	(9.4)	(5.3)%	**(27.1)**	(33.2)	(18.4)%
Other expense	**(8.0)**	(9.3)	(14.0)%	**(25.6)**	(32.6)	(21.5)%
Income before taxes	**$ 67.3**	$ 64.1	5.0%	**$ 136.7**	$ 131.3	4.1%
Sales in kilowatt-hours						
Residential	**897.2**	882.4	1.7%	**2,359.8**	2,381.9	(0.9)%
Commercial and industrial	**2,275.4**	2,275.9	%	**6,500.4**	6,422.5	1.2%
Wholesale	**1,587.7**	1,257.4	26.3%	**3,838.3**	3,455.6	11.1%
Other	**8.3**	8.4	(1.2)%	**26.8**	27.2	(1.5)%
Total sales in kilowatt-hours	**4,768.6**	4,424.1	7.8%	**12,725.3**	12,287.2	3.6%
Weather						
WPS:						
Heating degree days	**252**	246	2.4%	**3,864**	5,222	(26.0)%
Cooling degree days	**514**	494	4.0%	**789**	596	32.4%
UPPCO:						
Heating degree days	**434**	346	25.4%	**4,898**	5,941	(17.6)%

Cooling degree days	**236**	270	(12.6)%	**335**	301	11.3%

Third Quarter 2012 Compared with Third Quarter 2011

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 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.

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Regulated electric utility segment margins decreased $4.1 million, driven by:

- An approximate $4 million decrease in margins due to impacts from the WPS 2012 rate case re-opener. The PSCW approved a rate increase effective January 1, 2012. The rate increase was driven by anticipated increases in fuel and purchased power costs that did not materialize. Under the fuel rules, WPS deferred a portion of the difference between the costs included in rates and the actual fuel costs. This portion will be refunded to customers. Excluding the impact from fuel and purchased power costs, the 2012 rate case re-opener resulted in a rate decrease. The rate decrease was primarily driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions to the Focus on Energy Program was offset by lower operating expenses due to reduced payments to the program in 2012.
- An approximate $2 million decrease in wholesale margins, driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one large customer.
- An approximate $1 million net decrease in margins from residential and commercial and industrial customers due to variances related to sales volumes. A net increase in margins that resulted from an increase in sales volumes was more than offset by impacts from decoupling mechanisms. Although decoupling was implemented to minimize the impact of changes in sales volumes, WPS s decoupling mechanism does not cover all customers or jurisdictions. UPPCO s decoupling mechanism was terminated at the end of 2011.
    - A 1.7% increase in sales volumes to residential customers drove an approximate $1 million increase in margins.
    - A decrease in sales volumes to commercial and industrial customers resulted in an approximate $1 million decrease in margins.
    - Margins decreased approximately $1 million due to decoupling mechanisms.

These decreases were partially offset by:

- An approximate $2 million increase in margins due to a retail electric rate increase at UPPCO, effective January 1, 2012.
- A $1.5 million increase in margins due to the reversal of the first quarter of 2012 write-off of UPPCO s net regulatory asset related to its 2010 and 2011 decoupling deferrals. The write-off was reversed due to an MPSC order stating it had the authority to approve UPPCO s decoupling mechanism, as UPPCO s decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement.

Operating Income

Operating income at the regulated electric utility segment increased $1.9 million. The increase was driven by a $6.0 million decrease in operating expenses, partially offset by the $4.1 million decrease in margins discussed above. The decrease in operating expenses was driven by:

- A $2.9 million decrease in customer assistance expense driven by reduced payments to the Focus on Energy Program. These payments are recovered in rates.

- A $2.3 million decrease in maintenance expense, mainly due to fewer storms in WPS s service territories as well as fewer repairs at UPPCO s hydroelectric facilities in 2012.
- A $0.9 million decrease in bad debt expense, driven by the quarter-over-quarter impact of the 2011 write-off of receivables related to the bankruptcy of an UPPCO retail customer.
- These decreases were partially offset by a $1.1 million increase in employee benefit related expenses. The increase was primarily due to the quarter-over-quarter change in the fair value of amounts owed to plan participants under deferred compensation plans.

Other Expense

Other expense decreased $1.3 million, driven by an increase in AFUDC, primarily related to environmental compliance projects at the Columbia plant. Also contributing to the decrease in other expense was a decrease in interest expense, driven by the maturity and repayment of $150 million of long-term debt at WPS in August 2011.

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Nine Months 2012 Compared with Nine Months 2011

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 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.

Regulated electric utility segment margins decreased $14.9 million, driven by:

- An approximate $12 million decrease in margins due to impacts from the WPS 2012 rate case re-opener. The PSCW approved a rate increase effective January 1, 2012. The rate increase was driven by anticipated increases in fuel and purchased power costs that did not materialize. Under the fuel rules, WPS deferred a portion of the difference between the costs included in rates and the actual fuel costs. This portion will be refunded to customers. Excluding the impact from fuel and purchased power costs, the 2012 rate case re-opener resulted in a rate decrease. The rate decrease was primarily driven by reduced contributions to the Focus on Energy Program, which promotes residential and small business energy efficiency and renewable energy products. The margin impact from the reduction in contributions to the Focus on Energy Program was offset by lower operating expenses due to reduced payments to the program in 2012.
- An approximate $5 million decrease in wholesale margins, driven by a decrease in sales volumes. The decrease was primarily due to a reduction in sales to one large customer and the loss of wholesale customers.

These decreases were partially offset by:

- An approximate $4 million increase in margins due to a retail electric rate increase at UPPCO, effective January 1, 2012.
- An approximate $1 million net increase in margins from residential and commercial and industrial customers due to variances related to sales volumes. The margin impact from the period-over-period change in sales volumes was more than offset by the impacts from decoupling mechanisms. Although decoupling was implemented to minimize the impact of changes in sales volumes, WPS s decoupling mechanism does not cover all customers or jurisdictions. UPPCO s decoupling mechanism was terminated at the end of 2011.
  - A 0.9% decrease in sales volumes to residential customers, driven by warmer weather during the heating season, resulted in an approximate $2 million decrease in margins.
  - A 1.2% increase in sales volumes to commercial and industrial customers drove an approximate $2 million increase in margins.
  - Margins increased approximately $1 million due to decoupling mechanisms.

Operating Income

Operating income at the regulated electric utility segment decreased $1.6 million. The decrease was driven by the $14.9 million decrease in margins discussed above, partially offset by a $13.3 million decrease in operating expenses. The decrease in operating expenses was driven by:

- An $8.6 million decrease in customer assistance expense driven by reduced payments to the Focus on Energy Program. These payments are recovered in rates.
- A $4.1 million decrease in maintenance expense, primarily related to fewer planned outages at WPS s generation plants during 2012.
- A $1.3 million decrease in asset usage charges from IBS driven by certain computer hardware that was fully depreciated in 2011.
- A $1.1 million decrease in customer accounts expense driven by a decrease in maintenance costs related to the customer billing system.
- A $1.1 million decrease in bad debt expense, driven by the period-over-period impact of the 2011 write-off of receivables related to the bankruptcy of an UPPCO retail customer.
- A $1.1 million decrease in electric transmission expense.

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- These decreases were partially offset by a $3.5 million increase in employee benefit related expenses. The increase was primarily due to the period-over-period change in the fair value of amounts owed to plan participants under deferred compensation plans as well as an increase in postretirement medical expenses. Partially offsetting these increases was lower pension expense driven by an increase in contributions, which increased plan assets.

Other Expense

Other expense decreased $7.0 million, driven by a decrease in interest expense, primarily due to the maturity and repayment of $150 million of long-term debt at WPS in August 2011.

Electric Transmission Investment Segment Operations

(Millions)	Three Months Ended September 30 2012	2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	2011	Change in 2012 Over 2011
Earnings from equity method investments	**21.7**	19.9	9.0%	**63.8**	59.0	8.1%

Third Quarter 2012 Compared with Third Quarter 2011

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $1.8 million in the third quarter of 2012. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

Nine Months 2012 Compared with Nine Months 2011

Earnings from Equity Method Investments

Earnings from equity method investments at the electric transmission investment segment increased $4.8 million in 2012. The increase resulted from higher earnings related to our approximate 34% ownership interest in ATC. Our income increases each year as ATC continues to increase its rate base by investing in transmission equipment and facilities for improved reliability and economic benefits for customers.

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Integrys Energy Services Nonregulated Segment Operations

The retail electric and natural gas markets in which Integrys Energy Services operates continue to evolve. Sustained low commodity prices, capital costs, and market volatility have lowered the barrier to entry into the retail marketing segment of the industry. Coupled with growing market opportunities, this has resulted in increased competition, leading to downward pressure on per-unit margins. However, we have been able to take advantage of the continued growth opportunities in certain markets by increasing volumes contracted for future delivery. Our electric and natural gas volumes for future delivery have grown by 26.0% and 20.3%, respectively, when comparing our future contracted volumes at September 30, 2012 to September 30, 2011.

(Millions, except natural gas sales volumes)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Change in 2012 over 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Change in 2012 Over 2011
Revenues	**$ 335.5**	$ 333.1	0.7%	**$ 874.6**	$ 1,118.4	(21.8)%
Cost of sales	**258.7**	289.7	(10.7)%	**718.1**	979.2	(26.7)%
Margins	**76.8**	43.4	77.0%	**156.5**	139.2	12.4%
Margin Detail						
Realized retail electric margins	**27.2**	27.3	(0.4)%	**66.4**	71.6	(7.3)%
Realized wholesale electric margins **(1)**		0.1	(100.0)%	**(0.4)**	(1.3)	(69.2)%
Realized energy asset margins	**4.4**	5.7	(22.8)%	**11.2**	14.6	(23.3)%
Fair value accounting adjustments	**40.9**	8.4	386.9%	**39.1**	28.0	39.6%
Electric and other margins	**72.5**	41.5	74.7%	**116.3**	112.9	3.0%
Realized retail natural gas margins	**4.2**	4.2		**33.6**	34.6	(2.9)%
Realized wholesale natural gas margins **(1)**	**0.2**	(0.3)	N/A	**(1.4)**	1.1	N/A
Lower-of-cost-or-market inventory adjustments	**1.3**	(0.9)	N/A	**4.6**	(0.3)	N/A
Fair value accounting adjustments	**(1.4)**	(1.1)	27.3%	**3.4**	(9.1)	N/A
Natural gas margins	**4.3**	1.9	126.3%	**40.2**	26.3	52.9%
Operating and maintenance expense	**25.8**	22.7	13.7%	**78.4**	79.2	(1.0)%
Depreciation and amortization	**2.7**	2.5	8.0%	**7.5**	8.0	(6.3)%
Taxes other than income taxes	**0.6**	0.8	(25.0)%	**2.3**	4.1	(43.9)%
Operating income	**47.7**	17.4	174.1%	**68.3**	47.9	42.6%
Earnings (losses) from equity method investments	**0.5**	(0.1)	N/A	**1.2**	(0.1)	N/A
Miscellaneous income (expense)	**0.3**	(0.2)	N/A	**0.8**	1.1	(27.3)%
Interest expense	**(0.5)**	(0.6)	(16.7)%	**(1.5)**	(1.3)	15.4%
Other (expense) income	**0.3**	(0.9)	N/A	**0.5**	(0.3)	N/A
Income before taxes	**$ 48.0**	$ 16.5	190.9%	**$ 68.8**	$ 47.6	44.5%
Physically settled volumes						
Retail electric sales volumes in kwh	**4,010.6**	3,504.6	14.4%	**10,012.2**	9,454.1	5.9%
Wholesale assets and distributed solar electric sales volumes in kwh **(2)**	**26.3**	42.5	(38.1)%	**80.4**	87.8	(8.4)%
Retail natural gas sales volumes in bcf	**22.3**	18.3	21.9%	**89.4**	90.7	(1.4)%

kwh kilowatt-hours

bcf billion cubic feet

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

(2) The volumes related to the remaining wholesale electric contracts are not significant.

Third Quarter 2012 Compared with Third Quarter 2011

Revenues

Integrys Energy Services revenues increased $2.4 million, primarily driven by higher sales volumes, partially offset by lower average commodity prices.

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Margins

Integrys Energy Services margins increased $33.4 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 decreased $0.1 million, driven by competitive pressure on per-unit margins, mostly offset by higher sales volumes.

Realized energy asset margins

Realized energy asset margins decreased $1.3 million. The decrease was primarily due to the expiration of a long-term capacity contract related to the Combined Locks Energy Center in the fourth quarter of 2011.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $32.5 million increase in electric margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins did not change quarter over quarter. An increase in margins due to higher sales volumes was offset by a decrease in margins due to competitive pressure on per-unit margins.

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 $2.2 million quarter-over-quarter increase in margins from inventory adjustments was driven by lower write-downs and a higher volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services   margins. Fair value adjustments caused a $0.3 million decrease in natural gas margins quarter over quarter. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income

Integrys Energy Services   operating income increased $30.3 million. The main driver of the increase was the $33.4 million increase in margins discussed above, partially offset by a $3.1 million increase in operating expenses, driven by:

- A $1.5 million increase in professional fees, primarily related to the expansion of the residential and small commercial customer segment.
- A $1.0 million increase in payroll and employee benefit expenses.
- A $0.7 million increase in bad debt expense, driven by the negative quarter-over-quarter impact of fewer recovery opportunities in 2012 compared with 2011.

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Nine Months 2012 Compared with Nine Months 2011

Revenues

Integrys Energy Services revenues decreased $243.8 million, primarily driven by lower average commodity prices, partially offset by higher retail electric sales volumes.

Margins

Integrys Energy Services margins increased $17.3 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 decreased $5.2 million. The decrease was driven by the expiration at the end of 2011 of several large, lower-margin customer contracts in the Illinois market. Also contributing to the decrease in margins was competitive pressure on per-unit margins. These decreases were partially offset by increased margins from higher sales volumes.

Realized energy asset margins

Realized energy asset margins decreased $3.4 million. The decrease was primarily due to the expiration of a long-term capacity contract related to the Combined Locks Energy Center in the fourth quarter of 2011.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused an $11.1 million increase in electric margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply associated with electric sales contracts. These adjustments will reverse in future periods as contracts settle.

Natural Gas Margins

Realized retail natural gas margins

Realized retail natural gas margins decreased $1.0 million. The decrease was primarily driven by warmer weather period over period.

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 $4.9 million increase in margins from inventory adjustments was driven by a higher volume of inventory withdrawn from storage for which write-downs had previously been recorded.

Fair value accounting adjustments

Derivative accounting rules impact Integrys Energy Services margins. Fair value adjustments caused a $12.5 million increase in natural gas margins period over period. These adjustments primarily relate to physical and financial contracts used to reduce price risk for supply, storage, and transportation associated with natural gas sales contracts. These adjustments will reverse in future periods as contracts settle.

Operating Income

Integrys Energy Services operating income increased $20.4 million. The main driver of the increase was the $17.3 million increase in margins discussed above. In addition, operating expenses decreased $3.1 million, driven by:

- A $2.4 million decrease in fees related to an intercompany credit agreement with the holding company.
- A $1.8 million decrease in taxes other than income taxes.

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- A $1.8 million decrease in restructuring expenses.
- A $0.8 million net decrease in payroll and employee benefit expenses.

These decreases were partially offset by:

- A $2.6 million increase in professional fees, primarily related to the expansion of the residential and small commercial customer segment.
- A $1.6 million increase in bad debt expense, driven by the negative period-over-period impact of fewer recovery opportunities in 2012 compared with 2011.

Holding Company and Other Segment Operations

(Millions)	Three Months Ended September 30 2012	2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	2011	Change in 2012 Over 2011
Operating income (loss)	**$ (1.0)**	$ 1.3	N/A	**$ (3.6)**	$ 4.9	N/A
Other expense	**(7.0)**	(8.5)	(17.6)%	**(21.5)**	(25.6)	(16.0)%
Net loss before taxes	**$ (8.0)**	$ (7.2)	11.1%	**$ (25.1)**	$ (20.7)	21.3%

Third Quarter 2012 Compared with Third Quarter 2011

Operating Income (Loss)

Operating income at the holding company and other segment decreased $2.3 million to an operating loss in the third quarter of 2012. The decrease was driven by new business development costs associated with our compressed natural gas business, which we started in September 2011.

Other Expense

Other expense at the holding company and other segment decreased $1.5 million in 2012. The decrease was driven by the quarter-over-quarter impact of an impairment recorded on an investment in 2011. Lower amortization of credit facility fees in 2012 also contributed to the decrease.

Nine Months 2012 Compared with Nine Months 2011

Operating Income (Loss)

Operating income at the holding company and other segment decreased $8.5 million to an operating loss in 2012. The decrease was driven partially by new business development costs associated with our compressed natural gas business, which we started in September 2011. In addition, the holding company charged Integrys Energy Services $2.4 million less for fees related to use of an intercompany credit agreement.

Other Expense

Other expense at the holding company and other segment decreased $4.1 million in 2012. Interest expense on long-term debt decreased, driven by lower average outstanding long-term debt in 2012. The period-over-period impact of impairments recorded on an investment in 2011 also contributed to the decrease.

Provision for Income Taxes

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	**2011**	**2012**	**2011**
Effective Tax Rate	**28.4%**	**37.6%**	**32.2%**	**38.6%**

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Third Quarter 2012 Compared with Third Quarter 2011

Our effective tax rate decreased in the third quarter of 2012. The primary driver was a $5.9 million decrease in the provision for income taxes in the third quarter of 2012 as a result of WPS s 2013 rate case settlement agreement. WPS recorded a regulatory asset after the settlement agreement authorized recovery of deferred income taxes expensed in previous years in connection with the 2010 federal health care reform. See *Liquidity and Capital Resources, Other Future Considerations Federal Health Care Reform,* for more information.

Nine Months 2012 Compared with Nine Months 2011

Our effective tax rate decreased in 2012. We effectively settled certain state income tax examinations and remeasured uncertain tax positions included in our liability for unrecognized tax benefits in 2012. We decreased our provision for income taxes $6.2 million in 2012 primarily related to the effective settlement and remeasurement of these positions. We also decreased the provision for income taxes $5.9 million in 2012 as a result of WPS s 2013 rate case settlement agreement, as described above. Finally, we increased our multistate income tax obligations in 2011, driven by tax law changes in Michigan and Wisconsin. We recorded $6.0 million of income tax expense in 2011 when we increased our deferred income tax liabilities related to these tax law changes.

Discontinued Operations

(Millions)	Three Months Ended September 30 2012	Three Months Ended September 30 2011	Change in 2012 Over 2011	Nine Months Ended September 30 2012	Nine Months Ended September 30 2011	Change in 2012 Over 2011
Discontinued operations, net of tax	**$ (7.9)**	$ 0.2	N/A	**$ (8.7)**	$ (2.9)	200.0%

Third Quarter 2012 Compared with Third Quarter 2011

During the third quarter of 2012, we recorded a $7.9 million after-tax loss in discontinued operations at Integrys Energy Services. This loss was driven by impairment losses recognized on generation plants classified as held for sale that met the criteria for discontinued operations as of September 30, 2012. See Note 5, *Discontinued Operations,* for more information.

Nine Months 2012 Compared with Nine Months 2011

In 2012, we recorded an after-tax loss of $10.5 million in discontinued operations at Integrys Energy Services. This loss was driven by impairment losses recognized on generation plants classified as held for sale that met the criteria for discontinued operations as of September 30, 2012. See Note 5, *Discontinued Operations,* for more information. In 2011, we recorded an after-tax loss of $2.0 million in discontinued operations primarily related to operating losses on these generation plants.

Also in 2012, we recorded an after-tax gain of $1.8 million in discontinued operations at the holding company and other segment. In 2011, we recorded an after-tax loss of $0.9 million in discontinued operations at the holding company and other segment. Both adjustments related to remeasurements of uncertain tax positions included in our liability for unrecognized tax benefits to better reflect how the underlying positions are resolving themselves in various taxing jurisdictions. We also effectively settled certain state income tax examinations in 2012.

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 under existing credit facilities. Our borrowing costs can be impacted by short-term and long-term debt ratings assigned by independent credit rating agencies, as well as the market rates for interest. Our operating cash flows and access to capital markets can be impacted by macroeconomic factors outside of our control.

Operating Cash Flows

During the nine months ended September 30, 2012, net cash provided by operating activities was $544.4 million, compared with $634.7 million for the same period in 2011. The $90.3 million decrease in net cash provided by operating activities was largely driven by:

- A $138.1 million increase in contributions to pension and other postretirement benefit plans.
- A decrease in net income, adjusted for non-cash items.

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- Partially offsetting these decreases in cash was a $147.6 million increase in net cash provided by working capital. The increase was primarily due to the following:
  - An $89.5 million positive impact from a $5.7 million increase in other current liabilities in 2012, compared with an $83.8 million decrease in 2011. The change was driven by increases in 2012 in natural gas costs refundable to customers at PGL and NSG and fuel and purchased power costs refundable to customers at WPS, versus decreases in these liabilities in 2011.
  - A $50.6 million positive impact related to other current assets, driven primarily by tax impacts. Higher tax refunds were accrued in 2011than in 2012, primarily due to 100% bonus depreciation and increased tax deductions for pension funding in 2011. In addition, federal and state income tax refunds received in 2012 significantly exceeded amounts received in 2011.
  - A $50.5 million decrease in cash used for inventory, driven by declining natural gas prices and decreased coal freight costs in 2012.
  - Partially offsetting these increases was a $62.9 million decrease in cash generated from accounts receivable and accrued unbilled revenues. This decrease was driven by lower accounts receivable balances at the end of 2011 versus 2010, primarily due to lower natural gas prices and warmer period-over-period weather.

Investing Cash Flows

Net cash used for investing activities was $448.8 million during the nine months ended September 30, 2012, compared with $266.6 million for the same period in 2011. The $182.2 million increase in net cash used for investing activities was primarily due to a $234.6 million increase in capital expenditures (discussed below). The increase in capital expenditures was partially offset by a $43.9 million period-over-period positive impact related to the acquisition of the compressed natural gas fueling businesses in 2011.

Capital Expenditures

Capital expenditures by business segment for the nine months ended September 30 were as follows:

Reportable Segment (millions)	**2012**	**2011**	**Change**
Natural gas utility	**$ 278.6**	$ 124.3	$ 154.3
Electric utility	**113.5**	61.4	52.1
Integrys Energy Services	**27.0**	10.3	16.7
Holding company and other	**18.7**	7.2	11.5
Integrys Energy Group consolidated	**$ 437.8**	$ 203.2	$ 234.6

The increase in capital expenditures at the natural gas utility segment was primarily a result of the AMRP at PGL. The increase in capital expenditures at the electric utility segment was driven by environmental compliance projects at the Columbia plant in 2012. The increase in capital expenditures at the Integrys Energy Services segment was primarily a result of increased solar expenditures during 2012.

Financing Cash Flows

Net cash used for financing activities was $112.1 million during the nine months ended September 30, 2012, compared with $517.4 million for the same period in 2011. The $405.3 million decrease in net cash used for financing activities was driven by:

- The repayment of $556.2 million of long-term debt in 2011.
- A $46.9 million increase in cash received from stock option exercises.
- Partially offsetting these decreases in cash used for financing activities were the following:
  - A $133.2 million decrease in net borrowings of commercial paper.
  - A $74.2 million increase in cash used to purchase shares of our common stock on the open market to satisfy stock-based compensation obligations.

Significant Financing Activities

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

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For information on the issuance and redemption of long-term debt in 2012, see Note 10, *Long-Term Debt*.

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

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.

Discontinued Operations

Net cash provided by discontinued operations was $6.5 million during the nine months ended September 30, 2012, compared with $2.4 million of net cash used for discontinued operations during the same period in 2011. These cash flows primarily relate to the operations of WPS Westwood Generation, LLC, WPS Beaver Falls Generation, LLC, and WPS Syracuse Generation, LLC. See Note 5, *Discontinued Operations,* for more information.

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Future Capital Requirements and Resources

Contractual Obligations

The following table shows our contractual obligations as of September 30, 2012, including those of our subsidiaries.

		Payments Due By Period			
(Millions)	Total Amounts Committed	2012	2013 to 2014	2015 to 2016	2017 and Thereafter
Long-term debt principal and interest payments (1)	**$ 2,884.0**	**$ 303.1**	**$ 580.0**	**$ 632.9**	**$ 1,368.0**
Operating lease obligations	**88.3**	**2.2**	**14.6**	**9.9**	**61.6**
Commodity purchase obligations (2)	**2,226.5**	**217.8**	**804.2**	**301.3**	**903.2**
Purchase orders (3)	**410.3**	**406.8**	**3.5**		
Capital contributions to equity method investment	**3.4**	**3.4**			
Pension and other postretirement funding obligations (4)	**677.2**	**42.1**	**207.0**	**126.2**	**301.9**
Uncertain tax positions	**7.3**		**7.3**		
Total contractual cash obligations	**$ 6,297.0**	**$ 975.4**	**$ 1,616.6**	**$ 1,070.3**	**$ 2,634.7**

(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. Included in this amount is a $27.0 million loan that was repaid in November 2012 in connection with the pending sale of WPS Westwood Generation, LLC.

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

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

(4) Obligations for pension and other postretirement benefit plans, other than the Integrys Energy Group Retirement Plan, cannot reasonably be estimated beyond 2017.

The table above does not reflect payments related to the manufactured gas plant remediation liability of $593.3 million at September 30, 2012, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 12, *Commitments and Contingencies*, for more information about environmental liabilities. The table also does not reflect any payments for the September 30, 2012, liability of $6.8 million related to unrecognized tax benefits, as the amount and timing of the payments are uncertain. See Note 11, *Income Taxes*, for more information on unrecognized tax benefits.

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Capital Requirements

As of September 30, 2012, our subsidiaries capital expenditures for the three-year period 2012 through 2014 were expected to be as follows:

(Millions)		
PGL		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects	**$**	**901**
NSG		
Natural gas pipe distribution system and other projects		**89**
MERC		
Natural gas pipe distribution system and other projects		**53**
MGU		
Natural gas pipe distribution system, underground natural gas storage facilities, and other projects		**52**
WPS		
Acquisition of Fox Energy Center		**390**
Environmental projects		**386**
Electric and natural gas distribution projects		**166**
Electric and natural gas delivery and customer service projects		**107**
Other projects		**130**
UPPCO		
Repairs and safety measures at hydroelectric facilities		**16**
Other projects		**31**
Integrys Energy Services		
Solar and other projects		**136**
IBS		
Corporate or shared services software and infrastructure projects		**138**
ITF		
Compressed natural gas fueling stations		**109**
Total capital expenditures	**$**	**2,704**

We do not currently expect to provide capital contributions to INDU Solar Holdings, LLC during the remainder of 2012. However, we will continue to evaluate opportunities for investment in INDU Solar Holdings on an ongoing basis.

We expect to provide capital contributions to ATC (not included in the above table) of approximately $34 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, environmental requirements, regulatory constraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends.

Capital Resources

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management policies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage the liquidity and capital resource needs of the business segments. We plan to meet our capital requirements for the period 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.

At September 30, 2012, 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 9, *Short-Term Debt and Lines of Credit*, for more information on credit facilities and other short-term credit agreements. See Note 10, *Long-Term Debt*, for more information on long-term debt.

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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.

- In the PGL and NSG rate order approved on January 10, 2012, the ICC made the decoupling mechanism for residential and small commercial and industrial customers (based on total margin, excluding fixed charges) permanent for both companies. The Illinois Attorney General appealed the ICC s approval of decoupling and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. On May 16, 2012, the ICC issued a revised amendatory order granting the Illinois Attorney General s motion to make revenues collected under the permanent decoupling mechanism subject to refund. Refunds would be required if the Illinois Appellate Court (Court) finds that the ICC did not have the authority to approve decoupling and the Court orders a refund. As a result, the recovery of amounts related to decoupling is uncertain. Therefore, PGL and NSG reduced revenues by $13.2 million in the second quarter of 2012 related to decoupling amounts accrued for regulatory recovery as of March 31, 2012. These amounts and decoupling amounts accrued thereafter have a reserve established against them equal to the amount accrued. As of September 30, 2012, a reserve of $14.9 million was recorded. PGL and NSG plan to defend the authority of the ICC to approve the decoupling mechanism. PGL and NSG still intend to file with the ICC for rate recovery, beginning in 2013, for amounts accrued related to decoupling since the decoupling mechanism is still in place.

- Decoupling for natural gas and electric residential and small commercial and industrial customers 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. Decoupling was approved for 2013 on a pilot basis as part of WPS s 2013 settlement agreement. The decoupling mechanism will be based on total rate case-approved margins, rather than being calculated on a per-customer basis. It will continue to include an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service.

- Decoupling for UPPCO was approved for the majority of customer classes by the MPSC, effective January 1, 2010, and ended on December 31, 2011. As part of the 2012 settlement agreement, a new decoupling mechanism based on total margins will become effective for UPPCO on January 1, 2013. The new decoupling mechanism will not cover variations in volumes due to weather. UPPCO has no decoupling mechanism in place for 2012. In April 2012, the State of Michigan Court of Appeals ruled in a Detroit Edison proceeding that the MPSC did not have authority to approve electric decoupling mechanisms. This decision was not appealed. As a result of this ruling, UPPCO expensed $1.5 million in the first quarter of 2012 related to electric decoupling amounts previously deferred for regulatory recovery. However, on August 14, 2012, the MPSC issued an order stating it had the authority to approve UPPCO s decoupling mechanism, as UPPCO s decoupling mechanism was authorized pursuant to an MPSC-approved settlement agreement. Therefore, in the third quarter of 2012, UPPCO reversed the $1.5 million previously expensed in the first quarter of 2012.

- 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 cover variations in volumes due to weather, nor does it cover variations in volumes resulting from changes in customer count compared to rate case levels. The Court of Appeals ruling discussed above did not affect MGU s decoupling mechanism because it did not apply to natural gas.

- Decoupling for MERC was approved for residential and small commercial and industrial customers by the MPUC on a three-year trial basis. The decoupling mechanism does not cover variations in volumes resulting from changes in customer count compared to rate case levels. It includes an annual 10% cap based on distribution revenues approved in the rate case. Amounts recoverable from or refundable to customers are subject to this cap. The decoupling mechanism becomes effective when final rates are implemented, which is expected to be in December 2012.

See Note 20, *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. On March 27, 2012, the EPA issued a proposed rule that would impose a carbon dioxide emission rate limit on new electric generating units. The proposed limit may prevent the

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construction of new coal units until technology becomes commercially available. The EPA planned to propose performance standards for existing units in 2011 and finalize them in 2012; however, that proposal has been delayed.

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.

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 10 years, some provisions that affect the cost of providing benefits to retirees were reflected in our financial statements in 2010, 2011, and 2012. Many provisions of HCR were being challenged in the courts. On June 28, 2012, the U.S. Supreme Court upheld the law s individual mandate and left the provisions that impacted employer-sponsored health plans in place. The ruling eliminates much of the uncertainty concerning the impact of the law on employers who sponsor health care plans. Since the law was enacted in 2010, we have worked to create a long-term strategy for the implementation of the law. With the Supreme Court s decision, the implementation of this strategy continues. Our focus is on continued compliance with the law s many mandates, avoidance or reduction of tax impacts, and cost management. We successfully participated in the Early Retiree Reinsurance Program through the third quarter of 2011. Following the submission of our fourth quarter 2011 claim, we were informed that the program fund had been depleted and, as such, we are not anticipating any future funding.

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. 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. As part of the 2013 settlement agreement, WPS was authorized recovery in Wisconsin for the remaining \$5.9 million of income tax expense that relates to this tax law change. As a result, this amount was recorded as a regulatory asset at September 30, 2012.

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

The Dodd-Frank Act was signed into law in July 2010. Significant rulings essential to its framework are now beginning to become effective for certain companies. Since some of these final rules are being challenged in court, it is difficult to predict how they will ultimately affect us. Certain provisions of the Dodd-Frank Act relating to derivatives could increase capital and/or collateral requirements. We continue to monitor developments related to this act and their potential impacts on our future financial results. At this time, we are making the necessary changes to comply with the known rules.

Federal Tax Law Changes

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 that affect us, such as an extension to bonus depreciation and changes to listed property. We anticipate that these tax law changes will likely result in approximately $140.0 million of reduced cash payments for taxes through 2012. These tax incentives may also reduce utility rate base and, 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 relevant 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

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regulatory life of the renewable energy generating plant. Further, the allowed rate base 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, WPS submitted an application to the U.S. Department of the Treasury in the third quarter of 2012 for a cash grant for its Crane Creek wind project. If the amount of the cash grant awarded is acceptable and if regulatory treatment provided by the PSCW, the MPSC, and the FERC is acceptable, it is likely WPS will proceed with taking a grant in lieu of production tax credits for Crane Creek. Due to the effects of regulation, WPS does not anticipate a significant financial impact if this change is made.

CRITICAL ACCOUNTING POLICIES

We have reviewed our critical accounting policies and considered whether any new critical accounting estimates or other significant changes to our accounting policies require any additional disclosures. We have found that the disclosures made in our Annual Report on Form 10-K for the year ended December 31, 2011, are still current and that there have been no significant changes, except as follows:

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of April 1, 2012. 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 (ROE) for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, and discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is determined based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is based on its current allowed ROE adjusted for forecasted disallowed costs and expectations regarding the direction and magnitude of movements in interest rates. The terminal growth rate is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

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

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

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

The fair values calculated in the first step of the test for MGU, MERC, and PGL exceeded the carrying values by approximately 3%-20%. Due to the subjectivity of the assumptions and estimates underlying the impairment analyses, we cannot provide assurance that future analyses will not result in impairments. As a result, we performed a sensitivity analysis on key assumptions for these reporting units. The following table shows the change in each assumption, holding all other inputs constant, which would result in a fair value at or below carrying value, causing the applicable reporting unit to fail step one of the test.

Change in key inputs (in basis points)	**MGU**	**MERC**	**PGL**
Discount rate	25	75	250
Terminal year return on equity	(100)	(235)	(670)
Terminal year growth rate	(50)	(100)	N/A*

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

To measure commodity price risk exposure, we employ a number of controls and processes, including a value-at-risk (VaR) analysis of certain of our exposures. 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 99% confidence level. For further explanation of our VaR calculation, see our 2011 Annual Report on Form 10-K.

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

(Millions)	2012	2011
As of September 30	**$ 0.2**	$ 0.1
Average for 12 months ended September 30	**0.1**	0.2
High for 12 months ended September 30	**0.2**	0.3
Low for 12 months ended September 30	**0.1**	0.1

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

(Millions)	2012	2011
As of September 30	**$ 0.7**	$ 0.5
Average for 12 months ended September 30	**0.5**	0.8
High for 12 months ended September 30	**0.7**	1.2
Low for 12 months ended September 30	**0.4**	0.5

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

Interest Rate Risk

We are exposed to interest rate risk resulting from 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. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at September 30, 2012, a hypothetical increase in market interest rates of 100 basis points would have increased annual interest expense by $4.4 million. Comparatively, based on the variable rate debt outstanding at September 30, 2011, an increase in interest rates of 100 basis points would have increased annual interest expense by $2.7 million. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Other than the above-mentioned changes, our market risks have not changed materially from the market risks reported in our 2011 Annual Report on Form 10-K.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control

There were no changes in our internal control over financial reporting (as defined by Securities Exchange Act Rules 13a-15(f) and 15d-15(f)) during the quarter ended September 30, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

For information on material legal proceedings and matters, see Note 12, *Commitments and Contingencies*.

Item 1A. Risk Factors

There were no material changes in the risk factors previously disclosed in Part I, Item 1A of our 2011 Annual Report on Form 10-K, which was filed with the SEC on February 29, 2012.

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

Dividend Restrictions

We are a holding company and our ability to pay dividends is largely dependent upon the ability of our subsidiaries to make payments to us in the form of dividends or otherwise. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note 16, *Common Equity*.

Issuer Purchases of Equity Securities

The following table provides a summary of common stock purchases for the three months ended September 30, 2012:

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
07/01/12 - 07/31/12 (1) (2)	417,139	$ 58.66		
08/01/12 - 08/31/12 (1) (2)	126,597	59.93		
09/01/12 - 09/30/12 (1) (2)	84,342	52.97		

Total	**628,078**	**$**	**58.16**

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

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

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Item 5. Other Information

In June 2011, the Financial Accounting Standards Board issued guidance on the presentation of comprehensive income in the financial statements. The new guidance requires entities to present the components of net income and other comprehensive income as either one continuous statement or two consecutive statements. It eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. We adopted the new guidance on January 1, 2012, and will present the components of net income and other comprehensive income in two separate statements. The following presents the retrospective application of this guidance for each of the prior three years:

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)
Year Ended December 31

(Millions)	**2011**	**2010**	**2009**
Net Income (loss)	$ 230.5	$ 223.7	$ (67.5)
Other comprehensive income (loss), net of tax:			
Cash flow hedges			
Unrealized net gains (losses) arising during period, net of tax of $0.4 million, $(22.3) million, and $(21.4) million, respectively	1.5	(22.1)	(39.2)
Reclassification of net losses to net income, net of tax of $4.4 million, $27.0 million, and $38.4 million, respectively	7.4	26.6	70.7
Cash flow hedges, net	8.9	4.5	31.5
Defined benefit pension plans			
Pension and other postretirement benefit costs arising during period, net of tax of $(5.7) million, $(2.3) million, and $(3.3) million, respectively	(7.5)	(3.3)	(6.8)
Amortization of pension and other postretirement benefit costs included in net periodic benefit cost, net of tax of $0.6 million, $0.3 million, and $0.1 million, respectively	0.8	0.5	0.1
Defined benefit pension plans, net	(6.7)	(2.8)	(6.7)
Available-for-sale securities			
Unrealized holding gains arising during period, net of tax $ - million, $ - million, and $0.1 million, respectively			0.1
Reclassification of gains to net income, net of tax of $ - million, $ - million, and $(0.2) million, respectively			(0.2)
Available-for-sale securities, net			(0.1)
Foreign currency translation			
Foreign currency translation adjustments arising during period, net of tax of $ - million, $0.1 million, and $2.6 million, respectively		0.3	4.1
Foreign currency translation gain included in net income as a result of the Integrys Energy Services strategy change, net of tax $ - million, $(1.6) million, and $ - million, respectively		(2.7)	
Foreign currency translation, net		(2.4)	4.1
Other comprehensive income (loss), net of tax	2.2	(0.7)	28.8
Comprehensive income (loss)	232.7	223.0	(38.7)
Preferred stock dividends of subsidiary	(3.1)	(3.1)	(3.1)
Noncontrolling interest in subsidiaries		0.3	1.0
Comprehensive income (loss) attributed to common shareholders	$ 229.6	$ 220.2	$ (40.8)

Item 6. Exhibits

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

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SIGNATURE

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

	Integrys Energy Group, Inc.
Date: November 5, 2012	/s/ Linda M. Kallas Linda M. Kallas Vice President and Corporate Controller (Duly Authorized Officer and Chief Accounting Officer)

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INTEGRYS ENERGY GROUP

EXHIBIT INDEX TO FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2012

Exhibit No.	Description
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act and Rule 13a-14(a) or 15d-14(a) under the Securities Exchange Act of 1934 for Integrys Energy Group, Inc.
32	Written Statement of the Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350 for Integrys Energy Group, Inc.
101	Financial statements from the Quarterly Report on Form 10-Q of Integrys Energy Group, Inc. for the quarter ended September 30, 2012, filed on November 6, 2012, formatted in eXtensible Business Reporting Language (XBRL): (i) the Condensed Consolidated Statements of Income, (ii) the Condensed Consolidated Statements of Comprehensive Income, (iii) the Condensed Consolidated Balance Sheets, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Notes To Financial Statements, and (vi) document and entity information.