VECTREN CORP
Form 10-Q
November 08, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

OR

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

For the transition period from __________________ to __________________

Commission file number: 1-15467

VECTREN CORPORATION
(Exact name of registrant as specified in its charter)

INDIANA	35-2086905
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

One Vectren Square, Evansville, IN 47708
(Address of principal executive offices)
(Zip Code)

812-491-4000
(Registrant's telephone number, including area code)

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. ý Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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).
ý Yes ¨ No

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

Large accelerated filer ý Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company) Smaller reporting company ¨

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

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

Common Stock- Without Par Value	82,361,172	October 31, 2013
Class	Number of Shares	Date

Access to Information

Vectren Corporation makes available all SEC filings and recent annual reports free of charge through its website at www.vectren.com as soon as reasonably practicable after electronically filing or furnishing the reports to the SEC, or by request, directed to Investor Relations at the mailing address, phone number, or email address that follows:

Mailing Address:	Phone Number:	Investor Relations Contact:
One Vectren Square	(812) 491-4000	Robert L. Goocher
Evansville, Indiana 47708		Treasurer and Vice President, Investor Relations
		rgoocher@vectren.com

Definitions

BCF: billions of cubic feet

BTU: British thermal units

DOT: Department of Transportation

EPA: Environmental Protection Agency

FAC: Fuel Adjustment Clause

FASB: Financial Accounting Standards Board

FERC: Federal Energy Regulatory Commission

GAAP: Generally Accepted Accounting Principles

IDEM: Indiana Department of Environmental Management

IURC: Indiana Utility Regulatory Commission

MISO: Midcontinent Independent System Operator (formerly Midwest Independent System Operator)

MSHA: Mine Safety and Health Administration

MW: megawatts

MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)

OUCC: Indiana Office of the Utility Consumer Counselor

PUCO: Public Utilities Commission of Ohio

Throughput: combined gas sales and gas transportation volumes

XBRL: eXtensible Business Reporting Language

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash & cash equivalents	$9.3	$19.5
Accounts receivable - less reserves of $5.7 & $6.8, respectively	265.8	216.7
Accrued unbilled revenues	74.7	185.0
Inventories	138.4	158.6
Recoverable fuel & natural gas costs	19.5	25.3
Prepayments & other current assets	100.0	73.3
Total current assets	607.7	678.4
Utility Plant		
Original cost	5,326.9	5,176.8
Less: accumulated depreciation & amortization	2,136.3	2,057.2
Net utility plant	3,190.6	3,119.6
Investments in unconsolidated affiliates	25.2	78.1
Other utility & corporate investments	34.7	34.6
Other nonutility investments	35.6	24.9
Nonutility plant - net	626.3	598.0
Goodwill - net	262.3	262.3
Regulatory assets	261.6	252.7
Other assets	36.3	40.5
TOTAL ASSETS	$5,080.3	$5,089.1

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited – In millions)

	September 30, 2013	December 31, 2012
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$159.5	$180.6
Accounts payable to affiliated companies	—	29.7
Accrued liabilities	167.7	198.8
Short-term borrowings	249.2	278.8
Current maturities of long-term debt	30.3	106.4
Total current liabilities	606.7	794.3
Long-term Debt - Net of Current Maturities	1,627.0	1,553.4
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	709.0	637.2
Regulatory liabilities	381.9	364.2
Deferred credits & other liabilities	224.1	213.9
Total deferred credits & other liabilities	1,315.0	1,215.3
Commitments & Contingencies (Notes 7, 9-11)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.4 & 82.2 shares, respectively	707.6	700.5
Retained earnings	825.5	829.9
Accumulated other comprehensive (loss)	(1.5)	(4.3)
Total common shareholders' equity	1,531.6	1,526.1
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$5,080.3	$5,089.1

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited – in millions, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
OPERATING REVENUES				
Gas utility	$101.9	$100.2	$555.8	$508.5
Electric utility	165.8	167.9	470.0	456.6
Nonutility	311.9	245.4	785.4	623.6
Total operating revenues	579.6	513.5	1,811.2	1,588.7
OPERATING EXPENSES				
Cost of gas sold	27.5	28.1	235.4	197.0
Cost of fuel & purchased power	50.4	52.9	154.5	144.6
Cost of nonutility revenues	107.7	81.0	271.4	198.1
Other operating	227.5	195.6	652.5	557.2
Depreciation & amortization	70.7	61.9	205.7	188.9
Taxes other than income taxes	12.5	12.4	43.7	41.2
Total operating expenses	496.3	431.9	1,563.2	1,327.0
OPERATING INCOME	83.3	81.6	248.0	261.7
OTHER INCOME (EXPENSE)				
Equity in (losses) of unconsolidated affiliates	(0.3)	(3.6)	(57.6)	(17.8)
Other income – net	2.5	3.3	9.0	7.8
Total other income (expense)	2.2	(0.3)	(48.6)	(10.0)
INTEREST EXPENSE	21.3	23.9	66.3	71.8
INCOME BEFORE INCOME TAXES	64.2	57.4	133.1	179.9
INCOME TAXES	21.4	18.1	46.3	63.7
NET INCOME	$42.8	$39.3	$86.8	$116.2
AVERAGE COMMON SHARES OUTSTANDING	82.3	82.1	82.3	82.0
DILUTED COMMON SHARES OUTSTANDING	82.4	82.1	82.4	82.1
EARNINGS PER SHARE OF COMMON STOCK:				
BASIC	$0.52	$0.48	$1.05	$1.42
DILUTED	$0.52	$0.48	$1.05	$1.42
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.355	$0.350	$1.065	$1.050

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

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VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited – in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income	$42.8	$39.3	$86.8	$116.2
Other comprehensive income (OCI) of unconsolidated affiliates				
Net amount arising during the year before tax	0.1	0.7	4.6	6.7
Income taxes related to items of other comprehensive income	—	(0.3)	(1.8)	(3.2)
OCI of unconsolidated affiliates, net of tax	0.1	0.4	2.8	3.5
Remeasurement of postretirement benefit obligation	—	—	—	1.1
Total comprehensive income	$42.9	$39.7	$89.6	$120.8

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited – In millions)

	Nine Months Ended September 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$86.8	$116.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	205.7	188.9
Deferred income taxes & investment tax credits	32.4	52.6
Equity in losses of unconsolidated affiliates	57.6	17.8
Provision for uncollectible accounts	4.8	6.0
Expense portion of pension & postretirement benefit cost	6.7	6.8
Other non-cash charges - net	5.9	5.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	56.3	40.5
Inventories	20.2	(8.8)
Recoverable/refundable fuel & natural gas costs	5.8	(7.9)
Prepayments & other current assets	0.8	5.7
Accounts payable, including to affiliated companies	(58.4)	(50.8)
Accrued liabilities	(15.0)	(22.0)
Unconsolidated affiliate dividends	0.3	0.1
Employer contributions to pension & postretirement plans	(10.1)	(16.1)
Changes in noncurrent assets	(12.3)	(33.7)
Changes in noncurrent liabilities	1.4	(7.0)
Net cash provided by operating activities	388.9	293.8
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	332.7	99.5
Dividend reinvestment plan & other common stock issuances	5.3	5.6
Requirements for:		
Dividends on common stock	(87.6)	(86.1)
Retirement of long-term debt	(338.6)	(37.4)
Other financing activities	(2.0)	—
Net change in short-term borrowings	(29.6)	(10.9)
Net cash used in financing activities	(119.8)	(29.3)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Unconsolidated affiliate distributions	—	0.2
Other collections	5.0	8.9
Requirements for:		
Capital expenditures, excluding AFUDC equity	(273.9)	(274.9)
Other investments	(10.4)	(0.3)
Net cash used in investing activities	(279.3)	(266.1)
Net change in cash & cash equivalents	(10.2)	(1.6)
Cash & cash equivalents at beginning of period	19.5	8.6
Cash & cash equivalents at end of period	$9.3	$7.0

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

VECTREN CORPORATION AND SUBSIDIARY COMPANIES
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Organization and Nature of Operations

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company’s wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Utility Holdings’ consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 311,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining owns, and through its contract miners, mines and then sells coal. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and a leveraged lease, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services and coal. Prior to June 18, 2013, the Company, through Enterprises, was involved in nonutility activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance). Pursuant to service contracts, Energy Marketing provided the Company's regulated utilities natural gas supply services.

2. Basis of Presentation

The interim condensed consolidated financial statements included in this report have been prepared by the Company, without audit, as provided in the rules and regulations of the Securities and Exchange Commission and include a review of subsequent events through the date the financial statements were issued. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted as provided in such rules and regulations. The information in this report reflects all adjustments which are, in the opinion of management, necessary to fairly state the interim periods presented, inclusive of adjustments that are normal and recurring in nature. These condensed consolidated financial statements and related notes should be read in conjunction with the Company’s audited annual consolidated financial statements for the year ended December 31, 2012, filed with the Securities and Exchange Commission on February 15, 2013, on Form 10-K. Because of the seasonal nature of the Company’s operations, the results shown on a quarterly basis are not necessarily indicative of annual results.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

3. Earnings Per Share

The Company uses the two class method to calculate earnings per share (EPS). The two class method is an earnings allocation formula that treats a participating security as having rights to earnings that otherwise would have been available to common shareholders. The Company issues a minor amount of performance based awards that participate in dividends and are paid in shares. Under the two class method, earnings for a period are allocated between common shareholders and participating security holders based on their respective rights to receive dividends as if all undistributed book earnings for the period were distributed. Basic EPS is computed by dividing net income attributable to only the common shareholders by the weighted-average number of common shares outstanding for the period. Diluted EPS includes the impact of stock options and other equity based instruments to the extent the effect is dilutive. The following table illustrates the basic and dilutive EPS calculations for the periods presented in these financial statements.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2013	2012	2013	2012
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$42.8	$39.3	$86.8	$116.2
Denominator:				
Weighted average common shares outstanding (Denominator for Basic EPS)	82.3	82.1	82.3	82.0
Conversion of share based compensation arrangements	0.1	—	0.1	0.1
Adjusted weighted average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	82.4	82.1	82.4	82.1
Basic EPS	$0.52	$0.48	$1.05	$1.42
Diluted EPS	$0.52	$0.48	$1.05	$1.42

For the three and nine months ended September 30, 2013 and 2012, all options and equity based instruments were dilutive.

4. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received, which totaled $4.8 million in both the three months ended September 30, 2013 and 2012, as a component of operating revenues. During the nine months ended September 30, 2013 and 2012, these taxes totaled $20.9 million and $19.1 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

5. Retirement Plans & Other Postretirement Benefits

The Company maintains three qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and a postretirement benefit plan. The defined benefit pension plans and postretirement benefit plan, which cover eligible full-time regular employees, are primarily noncontributory. The postretirement health care and life insurance plans are a combination of self-insured and fully insured plans. The qualified pension plans and the SERP plan are aggregated under the heading “Pension Benefits.” The postretirement benefit plan is presented under the heading “Other Benefits.”

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Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows and the amortizations shown below are primarily reflected in Regulatory assets as a majority of pension and other postretirement benefits are being recovered through rates.

	Three Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$2.2	$1.9	$0.2	$0.2
Interest cost	3.6	3.8	0.5	0.6
Expected return on plan assets	(5.6)	(5.2)	—	—
Amortization of prior service cost	0.4	0.4	(0.8)	(1.0)
Amortization of actuarial loss	2.6	1.7	0.1	0.2
Net periodic benefit cost	$3.2	$2.6	$—	$—

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2013	2012	2013	2012
Service cost	$6.5	$5.7	$0.4	$0.4
Interest cost	11.0	11.6	1.5	2.3
Expected return on plan assets	(16.6)	(15.8)	—	—
Amortization of prior service cost	1.1	1.2	(2.4)	(1.6)
Amortization of transitional obligation	—	—	—	0.5
Amortization of actuarial loss	7.6	5.1	0.5	0.5
Net periodic benefit cost	$9.6	$7.8	$—	$2.1

Employer Contributions to Qualified Pension Plans

Currently, the Company expects to contribute approximately $10.0 million to qualified pension plans for 2013. During the nine months ended September 30, 2013, contributions of $7.5 million have been made.

6. Supplemental Cash Flow Information

As of September 30, 2013 and December 31, 2012, the Company has accruals related to utility and nonutility plant purchases totaling approximately $14.5 million and $11.1 million, respectively.

7. ProLiance Holdings, LLC

The Company has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets, along with the long-term pipeline and storage commitments, of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy), to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, Vectren's Indiana utilities as well as Citizens' utilities. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance's profits and losses; however, governance and voting rights remain at 50 percent for each member, and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

As a result of ProLiance exiting the natural gas marketing business on June 18, 2013, and subject to any final adjustment for working capital, the Company recorded its share of the loss on the disposition, termination of long-term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre-tax, or $26.8 million net of tax, during the second quarter of 2013. ProLiance funded an estimated equity shortfall at ProLiance Energy of $16.6 million at the time of the sale. To fund this estimated shortfall, the Company issued a note to ProLiance for its 61 percent ownership share of the $16.6 million shortfall, or $10.1 million, which was utilized by ProLiance to invest additional equity in ProLiance Energy. This interest-bearing note is classified as Other nonutility investments in the Condensed Consolidated Balance Sheets. After consideration of cash generated from the tax benefit of losses, the net impact on cash to the Company is generally neutral.

In addition, in connection with the sale, the Company and Citizens issued a guarantee to ETC. The guarantee issued by the Company and Citizens is a backup guarantee to the $50 million guarantee issued by ProLiance to ETC, and provides for a maximum guarantee of $30 million, or $18.3 million for the Company's 61 percent ownership share, and extends until 2016. This guarantee will be called upon only in the event of default as defined in the asset sale agreement and only if the ProLiance guarantee is not sufficient to satisfy the relevant obligations. Although there can be no assurance that these guarantees will not be called upon, the Company believes that the likelihood that the Company or ProLiance will be called upon to satisfy any obligations pursuant to these guarantees is remote.

As part of the transaction discussed above, ProLiance filed two petitions with the FERC seeking waivers of certain capacity release regulations. Under the first petition ProLiance sought to permanently release pipeline capacity to ETC that is used to provide service to retail customers. Under the second petition, ProLiance sought the same type of waiver in order to permanently release back to the utilities the pipeline contracts used to provide supply services to the utilities. The FERC has granted both requested waivers. ETC has taken assignment of the Portfolio Administration Agreements (PAAs) pursuant to which the utilities receive gas supply. With the receipt of the FERC waivers and with pipeline contracts having been transferred to the utilities, the utilities entered into an Asset Management Agreement (AMA) with ETC on September 1, 2013 and have temporarily released the pipeline contracts to ETC. ETC will fulfill the requirements of the PAAs through their remaining term ending in March 2016.

Vectren's remaining investment in ProLiance at September 30, 2013 is as follows and reflects that it relates primarily to ProLiance's investment in LA Storage, formerly named Liberty Gas Storage, LLC (Liberty) discussed below.

(In millions)	As of September 30, 2013
ProLiance Energy	$1.9
Midstream assets and cash from sale of storage assets	7.8
Liberty	21.7
Total investment in ProLiance	$31.4
Included in:	
Investments in unconsolidated affiliates	$21.3
Other nonutility investments	$10.1

Investment in Liberty

Liberty, a joint venture between ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and will connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, which resulted in Liberty recording a $132 million impairment charge. The Company, through ProLiance, recorded its share of the charge in 2009. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to connect the caverns to the pipeline system. As of September 30, 2013 and December 31, 2012, ProLiance's investment in Liberty was $35.6 million and $35.5 million, respectively.

Liberty received a demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") on February 8, 2011 related to a Sublease Agreement ("Sublease") between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of September 30, 2013, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Transactions with ProLiance

Purchases of natural gas from ProLiance for resale and for injections into storage for the three months ended September 30, 2012 totaled $57.2 million, and for the nine months ended September 30, 2013 and 2012, totaled $200.5 million and $186.9 million, respectively. The Company had no purchases during the third quarter of 2013 as a result of ProLiance exiting the natural gas marketing business. The Company did not have any amounts owed to ProLiance for purchases at September 30, 2013 and amounts owed to ProLiance at December 31, 2012 were $29.7 million and are included in Accounts payable to affiliated companies in the Condensed Consolidated Balance Sheets.

8. Financing Activities

Vectren Capital Term Loan

On August 6, 2013, Vectren Capital entered into a $100 million three year term loan agreement. Loans under the term loan agreement bear interest at either a Eurodollar rate or base rate plus an additional margin which is based on the Company's credit rating. The proceeds from this debt transaction were used to repay short-term borrowings outstanding under Vectren Capital's credit facility. The loan agreement is guaranteed by Vectren Corporation and includes customary representations, warranties, and covenants, including a leverage covenant consistent with leverage covenants contained in other Vectren Capital borrowing arrangements. The Company received net proceeds of approximately $100 million in August 2013.

SIGECO 2013 Debt Refund and Reissuance

During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

Utility Holdings Debt Transactions

On April 1, 2013, VUHI executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012 with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.20 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8

million and $79.6 million, respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement pursuant to which institutional investors have agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes will be unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. The Company expects to receive net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which will be used to refinance $100.0 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes. Subject to the satisfaction of customary conditions precedent, the notes will be funded on or about December 5, 2013, as a result of the delayed draw feature.

9. Commitments & Contingencies

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly-owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2013, parent level guarantees support a maximum of $25 million of Energy System Group's (ESG) performance contracting commitments and warranty obligations and $45 million of other project guarantees. The broader scope of ESG's performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $26 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations. As disclosed in Note 7, a guarantee issued and outstanding to an unrelated party in connection with ProLiance's disposition of certain of the net assets of ProLiance Energy totaled $18.3 million at September 30, 2013. Although there can be no assurance that these guarantees will not be called upon, the Company believes that the likelihood the Company will be called upon to satisfy any obligations pursuant to these guarantees is remote.

Performance Guarantees & Product Warranties

In the normal course of business, wholly-owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at September 30, 2013, there are 53 open surety bonds supporting future performance. The average face amount of these obligations is $4.7 million, and the largest obligation has a face amount of $57.3 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At September 30, 2013, approximately 43 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of September 30, 2013. In addition, ESG has an $8 million stand-alone letter of credit facility and as of September 30, 2013, $3.4 million was drawn upon and outstanding.

Legal & Regulatory Proceedings

The Company is party to various legal proceedings, audits, and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations or cash flows.

10. Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. Laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects and other infrastructure improvement projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

Ohio Recovery and Deferral Mechanisms
The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $101 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $8.7 million and $6.5 million at September 30, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company filed a request in August 2013 to extend the term of the DRR and expand the DRR to include recovery of other infrastructure investments. In that filing, the Company detailed a five-year capital expenditure plan for calendar years 2013 through 2017 totaling $187 million related to the applicable infrastructure investments. As is typical, other parties have intervened in the case and discovery is ongoing. The Company expects an order in early 2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law, reflecting its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. On August 29, 2013, the Company filed a request for the accounting authority described above on its capital expenditure program for the 2013 calendar year totaling $61.5 million. Of this amount, $34.8 million relates to expenditures that could be considered recoverable under the DRR discussed above. If not ultimately included in the DRR, the Company would anticipate deferral for future recovery through a House Bill 95 mechanism. In addition, the Company requested that subsequent requests for accounting authority will be filed annually in April. The Company expects an order before the end of 2013.

Indiana Recovery and Deferral Mechanisms
The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Vectren North and $3 million annually at Vectren South. The debt-related post in

service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North.

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these

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mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally-mandated investment, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years. Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. It is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Regulatory Mechanisms

The Company plans to utilize the mechanisms described above to recover certain costs of federally mandated projects and other capital investment projects outside of base rate proceedings. As discussed in detail above, the Company filed in Ohio in August 2013 a request seeking authority to extend the term of the DRR and expand the DRR to include for recovery of other infrastructure investments. The Company also expects to seek authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with the Pipeline Safety Law, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. Such requests are expected to be made in the near term. The Company has communicated its intent to make such filings with all appropriate parties. When filed, it is expected that the combined Indiana infrastructure replacement and improvement plan required by the legislation will reflect estimated construction costs of $800 to $900 million over the seven year period beginning in 2014 and $5 to $10 million in annual operating costs associated with compliance with new pipeline safety regulations. These recovery mechanisms are not yet in place in Indiana but are authorized under the newly enacted legislation described previously. While the regulatory framework is therefore not yet fully developed, it is expected that these costs will be recoverable under the mechanisms provided for in Senate Bills 251 and 560.

Vectren North Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case has now been reached with the Pipeline Safety Division of the IURC and a hearing on the settlement will be conducted in November 2013.

11. Environmental Matters

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality

Clean Air Interstate Rule / Cross-State Air Pollution Rule

In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA’s response to the US Court of Appeals for the District of Columbia’s (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court’s finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. In March 2013, the EPA filed a petition for review with the US Supreme Court, and in June 2013 the Supreme Court agreed to review the lower court decision. A decision by the Supreme Court is expected in 2014. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Environmental Regulations").

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR’s implementation by Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Notice of Violation for A.B. Brown Power Plant

The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed.

Information Request

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to each state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 and the Company is reviewing the proposal. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Environmental Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Due to the correlation among the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $80 million and $110 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. The Company is evaluating current and/or deferral of regulatory recovery that will moderate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company’s coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company’s ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change

In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward the EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two GHG regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is not expected until 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown

If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company’s fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

Manufactured Gas Plants

In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO’s service territory, all of which are currently enrolled in the IDEM’s VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $42.4 million ($23.2 million at Indiana Gas and $19.2 million at SIGECO). The estimated accrued costs are limited to the Company’s share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.7 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company’s utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2013 and December 31, 2012, approximately $5.1 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

12. Impact of Recently Issued Accounting Principles and Other Authoritative Guidance

Offsetting Assets and Liabilities

In January 2013, the FASB issued new accounting guidance on disclosures of offsetting assets and liabilities. This guidance amends prior requirements to add clarification to the scope of the offsetting disclosures. The amendment clarifies that the scope applies to derivative instruments accounted for in accordance with reporting topics on derivatives and hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with US GAAP or subject to an enforceable master netting arrangement or similar agreement. This guidance is effective for fiscal years beginning on or after January 1, 2013 and interim periods within annual periods. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

Accumulated Other Comprehensive Income (AOCI)
In February 2013, the FASB issued new accounting guidance on the reporting of reclassifications from AOCI. The guidance requires an entity to report the effect of significant reclassification from AOCI on the respective line items in net income if the amount being reclassified is required under US GAAP to be reclassified in its entirety to net income. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference to other disclosures required that provide additional details about these amounts. The new guidance is effective for fiscal years, and interim periods within annual periods, beginning after December 15, 2012. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the company's results of operations, cash flows or financial position.

Unrecognized Tax Benefit Presentation
In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when net operating loss carryforwards exist. The new standard was issued in an effort to eliminate diversity in practice resulting from a lack of guidance on this topic in the current US GAAP. The update provides that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances outlined in the update. The amendments in the update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, with early adoption permitted. This update is consistent with how the Company currently presents unrecognized tax benefits, therefore, adoption of this guidance resulted in no material impact on the Company's financial statements.

Final Federal Income Tax Regulations
In September 2013, the Internal Revenue Service (IRS) released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted for 2013 tax years. The Company intends to adopt the guidance for its 2014 tax year. The Company continues to evaluate the impact adoption of the regulations will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations to have a material impact on its consolidated financial statements.

13. Fair Value Measurements

The carrying values and estimated fair values using primarily Level 2 assumptions of the Company's other financial instruments follow:

	September 30, 2013		December 31, 2012	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,657.3	$1,807.1	$1,659.8	$1,873.3
Short-term borrowings	249.2	249.2	278.8	278.8
Cash & cash equivalents	9.3	9.3	19.5	19.5

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities marked to fair value.

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's long-term debt was estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Company for instruments with similar characteristics. Because of the maturity dates and variable interest rates of short-term borrowings and cash & cash equivalents, those carrying amounts approximate fair value. Because of the inherent difficulty of estimating interest rate and other market risks, the methods used to estimate fair value may not always be indicative of actual realizable value, and different methodologies could produce different fair value estimates at the reporting date.

Under current regulatory treatment, call premiums on reacquisition of utility-related long-term debt are generally recovered in customer rates over the life of the refunding issue or over a 15-year period. Accordingly, any reacquisition of this debt would not be expected to have a material effect on the Company's results of operations.

Because of the customized nature of notes receivable investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At September 30, 2013 and December 31, 2012, the fair value for these financial instruments was not estimated. The carrying value of these investments was approximately $12.4 million at September 30, 2013 and $2.1 million at December 31, 2012, and are included in Other nonutility investments.

14. Segment Reporting

The Company segregates its operations into three groups: 1) Utility Group, 2) Nonutility Group, and 3) Corporate and Other.

The Utility Group is comprised of Vectren Utility Holdings, Inc.’s operations, which consist of the Company’s regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations between Gas Utility Services and Electric Utility Services. Gas Utility Services provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio. Electric Utility Services provides electric distribution services to southwestern Indiana, and includes the Company’s power generating and wholesale power operations. Regulated operations supply natural gas and/or electricity to over one million customers. In total, the Utility Group reports three segments: Gas Utility Services, Electric Utility Services, and Other operations.

For 2013, the Nonutility Group reports five segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses. Results in the Energy Marketing segment include the results of the Company's investment in ProLiance through June 18, 2013 when it exited the natural gas marketing business (see Note 7 for more details of this transaction).

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company’s other operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company's reportable segments is summarized as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Revenues				
Utility Group				
Gas Utility Services	$101.9	$100.2	$555.8	$508.5
Electric Utility Services	165.8	167.9	470.0	456.6
Other Operations	9.5	10.2	28.5	30.1
Eliminations	(9.5)	(10.6)	(28.3)	(29.6)
Total Utility Group	267.7	267.7	1,026.0	965.6
Nonutility Group				
Infrastructure Services	234.3	182.2	580.5	449.2
Energy Services	19.4	34.2	63.8	85.6
Coal Mining	83.3	53.4	218.5	171.7
Other Businesses	—	0.1	—	0.4
Total Nonutility Group	337.0	269.9	862.8	706.9
Corporate & Other Group	0.3	—	0.3	—
Eliminations	(25.4)	(24.1)	(77.9)	(83.8)
Consolidated Revenues	$579.6	$513.5	$1,811.2	$1,588.7
Profitability Measure - Net Income				
Utility Group Net Income (Loss)				
Gas Utility Services	$(3.8)	$(2.7)	$37.2	$36.1
Electric Utility Services	26.6	26.6	60.1	59.4
Other Operations	2.5	2.5	7.3	7.0
Utility Group Net Income	25.3	26.4	104.6	102.5
Nonutility Group Net Income (Loss)				
Infrastructure Services	20.4	15.9	35.2	27.3
Energy Services	0.2	2.6	(2.0)	0.9
Coal Mining	(2.3)	(2.2)	(12.0)	—
Energy Marketing	—	(2.4)	(37.5)	(13.5)
Other Businesses	(0.8)	(0.7)	(1.3)	(0.6)
Nonutility Group Net Income (Loss)	17.5	13.2	(17.6)	14.1
Corporate & Other Group Net Loss	—	(0.3)	(0.2)	(0.4)
Consolidated Net Income	$42.8	$39.3	$86.8	$116.2

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Vectren Corporation (the Company or Vectren), an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana. The Company's wholly owned subsidiary, Vectren Utility Holdings, Inc. (Utility Holdings), serves as the intermediate holding company for three public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also earns a return on shared assets that provide information technology and other services to the three utilities. Utility Holdings' consolidated operations are collectively referred to as the Utility Group. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act). Vectren was incorporated under the laws of Indiana on June 10, 1999.

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. VEDO provides energy delivery services to approximately 311,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining owns, and through its contract miners, mines and then sells coal. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and a leveraged lease, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities by providing infrastructure services and coal. Prior to June 18, 2013, the Company, through Enterprises, was involved in nonutility activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance). Pursuant to service contracts, Energy Marketing provided the Company's regulated utilities natural gas supply services.

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings. The following discussion and analysis should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto as well as the Company's 2012 annual report filed on Form 10-K.

Executive Summary of Consolidated Results of Operations

In this discussion and analysis, the Company analyzes contributions to consolidated earnings and earnings per share from its Utility Group and Nonutility Group separately since each operates independently requiring distinct competencies and business strategies, offers different energy and energy related products and services, and experiences different opportunities and risks.

The Utility Group generates revenue primarily from the delivery of natural gas and electric service to its customers. The primary source of cash flow for the Utility Group results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services. The Company segregates its regulatory utility operations between a Gas Utility Services operating segment and an Electric Utility Services operating segment. The activities of, and revenues and cash flows generated by, the Nonutility Group are closely linked to the utility industry, and the results of those operations are generally impacted by factors similar to those impacting the overall utility industry. In addition, there are other operations, referred to herein as Corporate and Other, that include unallocated corporate expenses such as advertising and charitable contributions, among other activities.

Results for the three months ended September 30, 2013 were earnings of $42.8 million, or $0.52 per share, compared to earnings of $39.3 million, or $0.48 per share for the three months ended September 30, 2012. For the nine months ended September 30, 2013, consolidated net income was $86.8 million, or $1.05 per share, compared to $116.2 million, or $1.42 per share for the nine months ended September 30, 2012. In June 2013, ProLiance exited the gas marketing business through the disposition of certain of the net assets of its energy marketing subsidiary, ProLiance Energy, LLC. The Company is an equity method investor in ProLiance. A more detailed discussion of the disposition follows. Excluding the impact of the loss on the disposition and operating losses attributable to the Company's investment in ProLiance, totaling $37.5 million, or $0.46 per share, consolidated net income for the nine months ended September 30, 2013 was $124.3 million, or $1.51 per share. In 2012, excluding the impact of operating losses attributable to the Company's investment in ProLiance, totaling $2.4 million, or $0.02 per share, for the quarter and $13.5 million, or $0.16 per share, year to date, consolidated net income for the three and nine months ended September 30, 2012 was $41.7 million, or $0.50 per share, and $129.7 million, or $1.58 per share, respectively.

Losses Related to the Exit of the Gas Marketing Business by ProLiance

During 2013, the Company recorded its share of losses related to the sale of certain assets of ProLiance's subsidiary, ProLiance Energy. In the Condensed Consolidated Statements of Income, the impact associated with the loss on the disposition of these assets is a $41.9 million reduction to Equity in losses of unconsolidated affiliates, a $1.7 million charge to Operating expense, and an income tax benefit reflected in Income taxes of $16.8 million. More detailed information about ProLiance Energy's sale of certain assets is included in Note 7 to the consolidated financial statements. In addition to the losses associated with the sale of certain assets, the Company recorded its share of operating losses from ProLiance during 2013 totaling $10.7 million, net of tax, for the year to date period. In total, the Company's share of ProLiance's results reflects a net loss of $37.5 million, net of tax, for the year to date period. For the prior year, operating losses for ProLiance totaled $2.4 million and $13.5 million, net of tax, for the quarter and year to date periods ended September 30, 2012.

Consolidated Results Excluding the Results From ProLiance (See Page 26, regarding the Use of Non-GAAP Measures)

Net income and earnings per share, excluding results from ProLiance, in total and by group, for the three and nine months ended September 30, 2013 and 2012 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2013	2012	2013	2012
Net income, excluding ProLiance results	$42.8	$41.7	$124.3	$129.7
Attributed to:				
Utility Group	25.3	26.4	104.6	102.5
Nonutility Group, excluding ProLiance results	17.5	15.6	19.9	27.6
Corporate & other	—	(0.3)	(0.2)	(0.4)
Basic EPS, excluding ProLiance results	$0.52	$0.50	$1.51	$1.58
Attributed to:				
Utility Group	0.31	0.32	1.27	1.25
Nonutility Group, excluding ProLiance results	0.21	0.18	0.24	0.33

Utility Group
In the third quarter of 2013, the Utility Group earnings were $25.3 million, compared to $26.4 million in 2012. For the nine months ended September 30, 2013, Utility Group earnings were $104.6 million, compared to $102.5 million in 2012. The improved year to date 2013 results are primarily related to increased gas utility margins from small and large customers, return on electric transmission investment, and lower interest expense.

Gas Utility Services
During the third quarter of 2013, Gas Utility Services reported a seasonal loss of $3.8 million compared to a loss of $2.7 million in the third quarter of 2012. The third quarter 2013 results were lower primarily due to increased

depreciation expense associated with plant placed into service during the year. For the nine months ended September 30, 2013, Gas Utility Services' earnings were $37.2 million, compared to earnings of $36.1 million in 2012. Results in 2013 have been favorably impacted by small customer growth and increased large customer margin, offset by higher depreciation expense and operating costs. Results also continue to be favorably impacted by returns earned on increased investment in bare steel and cast iron pipe replacements, particularly in Ohio, and by lower interest expense.

Electric Utility Services
During the third quarter of 2013, Electric Utility Services' earnings were $26.6 million, flat to the same period in 2012. Electric Utility Services earned $60.1 million year to date in 2013, compared to earnings of $59.4 million for the nine months ended September 30, 2012. In both the third quarter and year to date periods, results were favorably impacted by lower interest expense offset by lower electric small customer margin resulting from conservation initiatives, net of lost margin recovery, and cooling weather that was significantly warmer in 2012 as compared to 2013. The 2012 results reflect refunds to customers pursuant to refunds arising from statutory net operating income limits. No such refunds have occurred or are expected in 2013.

Nonutility Group
During the 2013 third quarter, earnings from the Nonutility Group were $17.5 million, compared to $15.6 million, excluding ProLiance results, in 2012. For the nine months ended September 30, 2013, excluding ProLiance results, the Nonutility Group earned $19.9 million, compared to $27.6 million in 2012. Improved results in the third quarter of 2013 reflect increased Infrastructure Services' earnings due to increased demand for services. The year to date results for the Nonutility Group also reflect increased Infrastructure Services' earnings but were lower in total due primarily to losses at Coal Mining of $12.0 million in 2013, compared to break even in 2012. Coal Mining results during the quarter were about flat compared to the prior year, reflecting the execution of several improvement initiatives at the Prosperity Mine which have reduced the cost per ton at that mine over the last quarter. The quarter and year to date results also reflect the continued positive results from the Company's Oaktown mining complex both in volumes and cost per ton produced.

Dividends

Dividends declared for the three months ended September 30, 2013, were $0.355 per share, compared to $0.35 per share for the same period in 2012. Dividends declared for the nine months ended September 30, 2013, were $1.065 per share compared to $1.05 per share for the same period in 2012.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding ProLiance
This discussion and analysis contains non-GAAP financial measures that exclude the results related to the Company's investment in ProLiance.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income, excluding ProLiance results, to evaluate its results. Management believes analyzing underlying and ongoing business trends is aided by the removal of the ProLiance results and the rationale for using such non-GAAP measures is that, through the disposition by ProLiance of certain ProLiance Energy assets, the Company has now exited the gas marketing business.

A material limitation associated with the use of these measures is that the measures that exclude ProLiance results do not include all costs recognized in accordance with GAAP. Management compensates for this limitation by prominently displaying a reconciliation of these non-GAAP performance measures to their closest GAAP performance measures. This display also provides financial statement users the option of analyzing results as management does or by analyzing GAAP results.

Contribution to Vectren's basic EPS
Per share earnings contributions of the Utility Group, Nonutility Group excluding ProLiance results, and Corporate and Other are presented and are non-GAAP measures. Such per share amounts are based on the earnings contribution

of each group included in Vectren’s consolidated results divided by Vectren’s basic average shares outstanding during the period. The earnings per share of the groups do not represent a direct legal interest in the assets and liabilities allocated to the groups, but rather represent a direct equity interest in Vectren Corporation's assets and liabilities as a whole. These non-GAAP measures are used by management to evaluate the performance of individual businesses. In addition, other items giving rise to period over period variances, such as weather, may be presented on an after tax and per share basis. These amounts are calculated at a statutory tax rate divided by Vectren’s basic average shares outstanding during the period. Accordingly, management believes these measures are useful to investors in understanding each business’ contribution to consolidated earnings per share and in analyzing consolidated period to period changes and the potential for earnings per share contributions in future periods. Reconciliations of the non-GAAP measures to their most closely related GAAP measure of consolidated earnings per share are included throughout this discussion and analysis. The non-GAAP financial measures disclosed by the Company should not be considered a substitute for, or superior to, financial measures calculated in accordance with GAAP, and the financial results calculated in accordance with GAAP.

The following table reconciles consolidated net income, consolidated basic EPS, and Nonutility Group net income to those results excluding ProLiance results.

	Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
(In millions, except EPS)	GAAP Measure	Exclude ProLiance Results	Non-GAAP Measure	GAAP Measure	Exclude ProLiance Results	Non-GAAP Measure
Consolidated						
Net Income	$42.8	$—	$42.8	$86.8	$(37.5)	$124.3
Basic EPS	$0.52	$—	$0.52	$1.05	$(0.46)	$1.51
Nonutility Group Net Income (Loss)	$17.5	$—	$17.5	$(17.6)	$(37.5)	$19.9

	Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
(In millions, except EPS)	GAAP Measure	Exclude ProLiance Results	Non-GAAP Measure	GAAP Measure	Exclude ProLiance Results	Non-GAAP Measure
Consolidated						
Net Income	$39.3	$(2.4)	$41.7	$116.2	$(13.5)	$129.7
Basic EPS	$0.48	$(0.02)	$0.50	$1.42	$(0.16)	$1.58
Nonutility Group Net Income	$13.2	$(2.4)	$15.6	$14.1	$(13.5)	$27.6

Detailed Discussion of Results of Operations

Following is a more detailed discussion of the results of operations of the Company’s Utility and Nonutility operations. The detailed results of operations for these groups are presented and analyzed before the reclassification and elimination of certain intersegment transactions necessary to consolidate those results into the Company’s Condensed Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations, which consist of the Company's regulated utility operations and other operations that provide information technology and other support services to those regulated operations. Regulated operations consist of a natural gas distribution business that provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio and an electric transmission and distribution business, which provides electric distribution services to southwestern Indiana, and its power generating and wholesale power operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Utility Group operating results before certain intersegment eliminations and reclassifications for the three and nine months ended September 30, 2013 and 2012, follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2013	2012	2013	2012
OPERATING REVENUES				
Gas utility	$101.9	$100.2	$555.8	$508.5
Electric utility	165.8	167.9	470.0	456.6
Other	—	(0.4)	0.2	0.5
Total operating revenues	267.7	267.7	1,026.0	965.6
OPERATING EXPENSES				
Cost of gas sold	27.5	28.1	235.4	197.0
Cost of fuel & purchased power	50.4	52.9	154.5	144.6
Other operating	74.0	71.8	236.9	229.5
Depreciation & amortization	49.7	46.3	146.8	142.7
Taxes other than income taxes	11.6	11.5	41.3	39.0
Total operating expenses	213.2	210.6	814.9	752.8
OPERATING INCOME	54.5	57.1	211.1	212.8
OTHER INCOME - NET	2.0	2.3	6.8	5.2
INTEREST EXPENSE	15.6	17.8	49.2	53.5
INCOME BEFORE INCOME TAXES	40.9	41.6	168.7	164.5
INCOME TAXES	15.6	15.2	64.1	62.0
NET INCOME	$25.3	$26.4	$104.6	$102.5
CONTRIBUTION TO VECTREN BASIC EPS	$0.31	$0.32	$1.27	$1.25

Utility Group Margin

Throughout this discussion, the terms Gas Utility margin and Electric Utility margin are used. Gas Utility margin is calculated as Gas utility revenues less the Cost of gas sold. Electric Utility margin is calculated as Electric utility revenues less Cost of fuel & purchased power. The Company believes Gas Utility and Electric Utility margins are better indicators of relative contribution than revenues since gas prices and fuel and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers.

In addition, the Company separately reflects regulatory expense recovery mechanisms within Gas utility margin and Electric utility margin. These amounts represent dollar-for-dollar recovery of operating expenses. The Company utilizes these approved regulatory mechanisms to recover variations in operating expenses from the amounts reflected in base rates and are generally expenses that are subject to volatility. For example, demand side management and conservation expenses for both the gas and electric utilities; MISO administrative expenses for the Company's electric operations; uncollectible expense associated with the Company's Ohio gas customers; and recoveries of state mandated revenue taxes in both Indiana and Ohio are included in these amounts. Following is a discussion and analysis of margin generated from regulated utility operations.

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Gas Utility Margin (Gas utility revenues less Cost of gas sold)

Gas Utility margin and throughput by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Gas utility revenues	$101.9	$100.2	$555.8	$508.5
Cost of gas sold	27.5	28.1	235.4	197.0
Total gas utility margin	$74.4	$72.1	$320.4	$311.5
Margin attributed to:				
Residential & commercial customers	$56.4	$55.3	$243.4	$238.0
Industrial customers	12.1	11.9	41.9	39.8
Other	2.2	1.4	7.6	6.8
Regulatory expense recovery mechanisms	3.7	3.5	27.5	26.9
Total gas utility margin	$74.4	$72.1	$320.4	$311.5
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	6.5	6.3	73.6	57.3
Industrial customers	24.6	25.1	80.7	77.2
Total sold & transported volumes	31.1	31.4	154.3	134.5

Gas Utility margins were $74.4 million and $320.4 million for the three and nine months ended September 30, 2013, and compared to 2012, increased $2.3 million in the quarter and $8.9 million year to date. Excluding the impact of regulatory expense recovery mechanisms, small customer margins increased $1.1 million quarter over quarter and $5.4 million year to date, compared to the prior year. Growth in residential and commercial customers favorably impacted small customer margins by approximately $0.4 million for the quarter and $2.3 million for the year to date. In addition, recovery related to investments in infrastructure in Ohio increased margin $0.7 million and $2.4 million in the quarter and year to date periods, respectively, compared to the prior year. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 103 percent of normal in Ohio and equal to normal in Indiana during the nine months ended September 30, 2013, compared to 83 percent of normal in Ohio and 71 percent of normal in Indiana during 2012, only had a slight favorable impact to small customer margin. Large customer margins increased $0.2 million and $2.1 million in the quarter and year to date periods, respectively, compared to the prior year, on increasing volumes.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)

Electric Utility margin and volumes sold by customer type follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Electric utility revenues	$165.8	$167.9	$470.0	$456.6
Cost of fuel & purchased power	50.4	52.9	154.5	144.6
Total electric utility margin	$115.4	$115.0	$315.5	$312.0
Margin attributed to:				
Residential & commercial customers	$73.8	$77.0	$195.0	$200.1
Industrial customers	28.6	29.3	82.5	83.9
Other	1.4	(0.9)	3.1	(0.4)
Regulatory expense recovery mechanisms	2.2	0.9	6.7	2.9
Subtotal: retail	$106.0	$106.3	$287.3	$286.5
Wholesale power & transmission system margin	9.4	8.7	28.2	25.5
Total electric utility margin	$115.4	$115.0	$315.5	$312.0
Electric volumes sold in GWh attributed to:				

Residential & commercial customers	769.6	813.8	2,072.1	2,138.2
Industrial customers	729.7	732.5	2,087.0	2,127.6
Other customers	4.9	5.3	15.5	16.0
Total retail volumes sold	1,504.2	1,551.6	4,174.6	4,281.8

Retail

Electric retail utility margins were $106.0 million and $287.3 million for the three and nine months ended September 30, 2013, and, compared to 2012, decreased by $0.3 million in the quarter and increased $0.8 million year to date. Excluding the impact of regulatory expense recovery mechanisms, small customer margins decreased by $3.2 million for the quarter and $5.1 million year to date compared to 2012. Electric results are not protected by weather normalizing mechanisms. Cooling degree days in 2013 were 101 percent of normal compared to 131 percent of normal in 2012, resulting in lower small customer margin of $4.5 million in the quarter and $3.3 million year to date, compared to the prior year. In addition, small customer margin declined $0.4 million for the quarter and $3.5 million for the year to date period as a result of customer energy conservation, net of approved lost margin recovery mechanisms. These declines in small customer margin were somewhat offset by an unfavorable adjustment in the prior year of $1.6 million. Large customer margins for the third quarter of 2013 declined $0.7 million from the prior year, and for the nine months decreased $1.4 million from 2012 on lower volumes. Other margin was higher in both the quarter and year to date periods due to refunds during 2012 resulting from statutory net operating income limits. Margin from regulatory expense recovery mechanisms increased $1.3 million for the third quarter and $3.8 million for the nine months compared to 2012, driven by increased operating expenses associated with the electric state-mandated conservation programs. This is offset by a corresponding increase in operating expenses when compared to 2012.

Margin from Wholesale Electric Activities

The Company earns a return on electric transmission projects constructed by the Company in its service territory that meet the criteria of MISO's regional transmission expansion plans and also markets and sells its generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales are generated in the MISO Day Ahead and Real Time markets when sales into the MISO in a given hour are greater than amounts purchased for native load. Further detail of MISO off-system margin and transmission system margin follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2013	2012	2013	2012
Transmission system sales	$8.6	$7.7	$23.1	$20.8
Off-system sales	0.8	1.0	5.1	4.7
Total wholesale margin	$9.4	$8.7	$28.2	$25.5

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $23.1 million and $20.8 million during the nine months ended September 30, 2013 and 2012, respectively. During the 2013 third quarter, transmission system margin was $8.6 million compared to $7.7 million for the same period in 2012. Increases are primarily due to increased investment in qualifying projects. As of September 30, 2013, the Company had invested approximately $159 million in qualifying projects. These projects include an interstate 345 Kv transmission line that connects Vectren's A.B. Brown Generating Station to a generating station in Indiana owned by Duke Energy to the north and to a generating station in Kentucky owned by Big Rivers Electric Corporation to the south; a substation; and another transmission line. Once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance, and operating expenses are also recovered. The 345 Kv project is the largest of these qualifying projects, with a cost of $107 million that earns the FERC approved equity rate of return, including while under construction. The last segment of that project was placed into service in December 2012.

For the nine months ended September 30, 2013, margin from off-system sales was $5.1 million, compared to $4.7 million for the nine months ended September 30, 2012. In the third quarter of 2013, margin from off system sales was $0.8 million compared to $1.0 million in 2012. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million per year be shared equally with customers. Results for the periods presented reflect the impact of that sharing.

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Utility Group Operating Expenses

Other Operating
During the third quarter of 2013, other operating expenses increased $2.2 million, partially related to the timing of power supply operating costs. For the nine months ended September 30, 2013, other operating expenses were $236.9 million, an increase of $7.4 million, compared to 2012. Excluding pass through costs, other operating expenses increased $5.2 million year to date, compared to the same period in 2012, primarily associated with increased expense related to company stock price driven performance based compensation. Though higher year to date, operating costs are being managed to be generally flat to the 2012 targeted levels on an annual basis, over time.

Depreciation & Amortization
In the third quarter of 2013, depreciation and amortization expense was $49.7 million, compared to $46.3 million in 2012. For the nine months ended September 30, 2013, depreciation and amortization expense was $146.8 million, which represents an increase of $4.1 million compared to 2012. Both the year to date and quarter periods reflect increased plant placed into service.

Taxes Other Than Income Taxes
Taxes other than income taxes were essentially flat during the three months ended September 30, 2013, compared to 2012. Year to date, taxes other than income taxes were $41.3 million compared to $39.0 million for the year to date period in 2012. The year to date increase of $2.3 million is primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These expenses are offset dollar-for-dollar with lower gas utility and electric utility revenues.

Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
Vectren monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. Vectren's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio, the primary purpose of which is preventive maintenance and continual renewal and operational improvement. Laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects and other infrastructure improvement projects, outside of a base rate proceeding. Utilization of these recovery mechanisms is discussed below.

Ohio Recovery and Deferral Mechanisms
The PUCO order approving the Company's 2009 base rate case in the Ohio service territory authorized a distribution replacement rider (DRR). The DRR's primary purpose is recovery of investments in utility plant and related operating expenses associated with replacing bare steel and cast iron pipelines and certain other infrastructure. This rider is updated annually for qualifying capital expenditures and allows for a return to be earned on those capital expenditures based on the rate of return approved in the 2009 base rate case. In addition, deferral of depreciation and the ability to accrue debt-related post in service carrying costs is also allowed until the related capital expenditures are recovered through the DRR. The order also established a prospective bill impact evaluation on the annual deferrals, limiting the deferrals at a level which would equal a change over the prior year rate of $1.00 per residential and general service customer per month. To date, the Company has made capital investments under this rider totaling $101 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $8.7 million and $6.5 million at September 30, 2013 and December 31, 2012, respectively. The DRR's initial five year term expires in early 2014. The Company filed a request in August 2013 to extend the term of the DRR and expand the DRR to include recovery of other infrastructure investments. In that filing, the Company detailed a five-year capital expenditure plan for calendar years 2013 through 2017 totaling $187 million related to the applicable infrastructure investments. As is typical, other parties have intervened in the case and discovery is ongoing. The Company expects an order in early

2014.

In June 2011, Ohio House Bill 95 was signed into law. Outside of a base rate proceeding, this legislation permits a natural gas company to apply for recovery of much of its capital expenditure program. The legislation also allows for the deferral of costs, such as depreciation, property taxes, and debt-related post in service carrying costs. On December 12, 2012, the PUCO issued an order approving the Company's initial application using this law, reflecting its $23.5 million capital expenditure program covering the fifteen month period ending December 31, 2012. Such capital expenditures include infrastructure expansion and improvements not covered by the DRR as well as expenditures necessary to comply with PUCO rules, regulations, orders, and system expansion to some new customers. The order also established a prospective bill impact evaluation on the cumulative deferrals, limiting the total deferrals at a level which would equal $1.50 per residential and general service customer per month. On August 29, 2013, the Company filed a request for the accounting authority described above on its capital expenditure program for the 2013 calendar year totaling $61.5 million. Of this amount, $34.8 million relates to expenditures that could be considered recoverable under the DRR discussed above. If not ultimately included in the DRR, the Company would anticipate deferral for future recovery through a House Bill 95 mechanism. In addition, the Company requested that subsequent requests for accounting authority will be filed annually in April. The Company expects an order before the end of 2013.

Indiana Recovery and Deferral Mechanisms

The Company's Indiana natural gas utilities received orders in 2008 and 2007 associated with the most recent base rate cases. These orders authorized the deferral of financial impacts associated with bare steel and cast iron replacement activities. The orders provide for the deferral of depreciation and post in service carrying costs on qualifying projects totaling $20 million annually at Vectren North and $3 million annually at Vectren South. The debt-related post in service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. Such deferral is limited by individual qualifying project to three years after being placed into service at Vectren South and four years after being placed into service at Vectren North.

In April 2011, Senate Bill 251 was signed into Indiana law. The law provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a general rate case. Such costs include a return on the federally mandated capital investment, along with recovery of depreciation and other operating costs associated with these mandates. The remaining 20 percent of those costs are to be deferred for future recovery in the utility's next general rate case.

In April 2013, Senate Bill 560 was signed into law. This legislation supplements Senate Bill 251 described above, which addressed federally-mandated investment, and provides for cost recovery outside of a base rate proceeding for projects that either improve electric and gas system reliability and safety or are economic development projects that provide rural areas with access to gas service. Provisions of the legislation require that, among other things, requests for recovery include a seven-year project plan. Once the plan is approved by the IURC, 80 percent of such costs are eligible for recovery using a periodic rate adjustment mechanism. Recoverable costs include a return on and of the investment, as well as property taxes and operating expenses. The remaining 20 percent of project costs are to be deferred for future recovery in the Company's next general rate case. The adjustment mechanism is capped at an annual increase in retail revenues of no more than two percent.

Pipeline Safety Law

On January 3, 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (Pipeline Safety Law) was signed into law. The Pipeline Safety Law, which reauthorizes federal pipeline safety programs through fiscal year 2015, provides for enhanced safety, reliability, and environmental protection in the transportation of energy products by pipeline. The law increases federal enforcement authority; grants the federal government expanded authority over pipeline safety; provides for new safety regulations and standards; and authorizes or requires the completion of several pipeline safety-related studies. The DOT is required to promulgate a number of new regulatory requirements over the next two years. Those regulations may eventually lead to further regulatory or statutory requirements.

The Company continues to study the impact of the Pipeline Safety Law and potential new regulations associated with its implementation. It is expected that the law will result in further investment in pipeline inspections, and where necessary, additional investments in pipeline infrastructure and, therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses.

Requests for Recovery Under Regulatory Mechanisms

The Company plans to utilize the mechanisms described above to recover certain costs of federally mandated projects and other capital investment projects outside of base rate proceedings. As discussed in detail above, the Company filed in Ohio in August 2013 a request seeking authority to extend the term of the DRR and expand the DRR to include for recovery of other infrastructure investments. The Company also expects to seek authority to recover appropriate costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with the Pipeline Safety Law, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. Such requests are expected to be made in the near term.

The Company has communicated its intent to make such filings with all appropriate parties. When filed, it is expected that the combined Indiana infrastructure replacement and improvement plan required by the legislation will reflect estimated construction costs of $800 to $900 million over the seven year period beginning in 2014 and $5 to $10 million in annual operating costs associated with compliance with new pipeline safety regulations. These recovery mechanisms are not yet in place in Indiana but are authorized under the newly enacted legislation described previously. While the regulatory framework is therefore not yet fully developed, it is expected that these costs will be recoverable under the mechanisms provided for in Senate Bills 251 and 560.

Vectren North Pipeline Safety Investigation
On April 11, 2012, the IURC's pipeline safety division filed a complaint against Vectren North alleging several violations of safety regulations pertaining to damage that occurred at a residence in Vectren North's service territory during a pipeline replacement project. The Company negotiated a settlement with the IURC's pipeline safety division, agreeing to a fine and several modifications to the Company's operating policies. The amount of the fine was not material to the Company's financial results. The IURC approved the settlement but modified certain terms of the settlement and added a requirement that Company employees conduct inspections of pipeline excavations. The Company sought and was granted a request for rehearing on the sole issue related to the requirement to use Company employees to inspect excavations. A settlement in the case has now been reached with the Pipeline Safety Division of the IURC and a hearing on the settlement will be conducted in November 2013.

Environmental Matters

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company is currently evaluating the impact Senate Bill 251 may have on its operations, including applicability of the stricter regulations the EPA is currently considering involving air quality, fly ash disposal, cooling tower intake facilities, waste water discharges, and greenhouse gases. These issues are further discussed below.

Air Quality
Clean Air Interstate Rule / Cross-State Air Pollution Rule
In July 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSAPR was the EPA’s response to the US Court of Appeals for the District of Columbia’s (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010, with a second phase of reductions in 2015. In an effort to address the Court’s finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO_2 and NOx allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSAPR set individual state caps for SO_2 and NOx emissions. However, unlike CAIR in which states allocated allowances to generating units through state implementation plans, CSAPR allowances were allocated to individual units directly through the federal rule. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. Multiple administrative and judicial challenges were filed. On December 30, 2011, the Court granted a stay of CSAPR and left CAIR in place pending its review. On August 21, 2012, the Court vacated CSAPR and directed the EPA to continue to administer CAIR. In October 2012, the EPA filed its request for a hearing before the full federal appeals court that struck down the CSAPR. EPA's request for rehearing was denied by the Court on January 24, 2013. In March 2013, the EPA filed a petition for review with the US Supreme Court, and in June 2013 the Supreme Court agreed to review the lower court decision. A decision by the Supreme Court is expected in 2014. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Environmental Regulations").

Mercury and Air Toxics (MATS) Rule

On December 21, 2011, the EPA finalized the Utility MATS Rule. The MATS Rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium), and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual electric generating units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (April 2015). Initiatives to suspend CSAPR's implementation by Congress also apply to the implementation of the MATS rule. Multiple judicial challenges were filed and briefing is proceeding. The EPA agreed to reconsider MATS requirements for new construction. Such requirements are more stringent than those for existing plants. Utilities planning new coal-fired generation had argued standards outlined in the MATS could not be attained even using the best available control technology. The EPA issued its revised emission limits for new construction in March 2013.

Notice of Violation for A.B. Brown Power Plant
The Company received a notice of violation (NOV) from the EPA in November 2011 pertaining to its A.B. Brown power plant. The NOV asserts that when the power plant was equipped with SCRs the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed.

Information Request
SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own a 300 MW Unit 4 at the Warrick Power Plant as tenants in common. AGC and SIGECO also share equally in the cost of operation and output of the unit. In January 2013, AGC received an information request from the EPA under Section 114 of the Clean Air Act for historical operational information on the Warrick Power Plant. In April 2013, ALCOA filed a timely response to the information request.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized, the regulation will leave it to each state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2013. Depending on the final rule and on the Company's facts and circumstances, capital investments could approximate $40 million if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recovered under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, EPA sets technology-based guidelines for water discharges from new and existing facilities. EPA is currently in the process of revising the existing steam electric effluent limitation guidelines that set the technology-based water discharge limits for the electric power industry. EPA is focusing its rulemaking on wastewater generated primarily by pollution control equipment necessitated by the comprehensive air regulations. The EPA released proposed rules on April 19, 2013 and the Company is reviewing the proposal. At this time, it is not possible to estimate what potential costs may be required to meet these new water discharge limits, however costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Conclusions Regarding Environmental Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 scrubber at its generating facility that is jointly owned with AGC (the Company's portion is 150

MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order obtained April 27, 2011. SIGECO's coal-fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

Utilization of the Company's NOx and SO2 allowances can be impacted as regulations are revised and implemented. Most of these allowances were granted to the Company at zero cost; therefore, any reduction in carrying value that could result from future changes in regulations would be immaterial.

The Company continues to review the sufficiency of its existing pollution control equipment in relation to the requirements described in the MATS Rule, the recent renewal of water discharge permits, and the NOV discussed above. Due to the correlation among the various requirements set forth, it is possible some operational modifications to the control equipment will be required. Additional capital investments, operating expenses, and possibly the purchase of emission allowances may be required. The Company is continuing to evaluate potential technologies to address compliance and what the additional costs may be associated with these efforts. Currently, it is expected that the capital costs could be between $80 million and $110 million. Compliance is required by government regulation, and the Company believes that such additional costs, if incurred, should be recoverable under Senate Bill 251 referenced above. The Company is evaluating current and/or deferral of regulatory recovery that will moderate the impact on customer rates in the near term.

Coal Ash Waste Disposal & Ash Ponds
In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company’s coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules have not been finalized given oversight hearings, congressional interest, and other factors.

At this time, the majority of the Company’s ash is being beneficially reused. However, the alternatives proposed would require modification to, or closure of, existing ash ponds. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. Costs for compliance with these regulations should qualify as federally mandated regulatory requirements and be recoverable under Senate Bill 251 referenced above.

Climate Change
In April 2007, the US Supreme Court determined that greenhouse gases (GHG's) meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether GHG emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward the EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress.

The EPA has promulgated two GHG regulations that apply to the Company’s generating facilities. In 2009, the EPA finalized a mandatory GHG emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of GHG's a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The EPA's PSD and Title V permitting rules for GHG's were upheld by the US Court of Appeals for the District of Columbia. In 2012, the EPA proposed New Source Performance Standards (NSPS) for GHG's for new electric generating facilities under the Clean Air Act Section 111(b). On October 15, the US Supreme Court agreed to review a focused appeal on the issue of whether the GHG rule applicable to mobile sources triggered PSD permitting for all stationary sources such as Vectren's power plants. A decision is not expected until 2014.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to re-propose and finalize the new source rule expeditiously, and by June 2014 propose, and by June 2015 finalize, NSPS standards for GHG's for existing electric generating units which would apply to Vectren's power plants. States must have their implementation plans to the EPA no later than June 2016. The President's Climate Action Plan did not provide any detail as to actual emission targets or compliance requirements. The Company anticipates that these initial standards will focus on power plant efficiency and other coal fleet carbon intensity reduction measures. The Company believes that such additional costs, if necessary, should be recoverable under Indiana Senate Bill 251 referenced above.

Numerous competing federal legislative proposals have also been introduced in recent years that involve carbon, energy efficiency, and renewable energy. Comprehensive energy legislation at the federal level continues to be debated, but there has been little progress to date. The progression of regional initiatives throughout the United States has also slowed.

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO_2 and other GHG's or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in GHG emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control GHG emissions. A preliminary investigation demonstrated costs to comply would be significant, first with regard to operating expenses and later for capital expenditures as technology becomes available to control GHG emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions should be considered a federally mandated cost of providing electricity, and as such, the Company believes such costs and expenditures should be recoverable from customers through Senate Bill 251.

Senate Bill 251 also established a voluntary clean energy portfolio standard that provides incentives to Indiana electricity suppliers participating in the program. The goal of the program is that by 2025, at least 10 percent of the total electricity obtained by the supplier to meet the energy needs of Indiana retail customers will be provided by clean energy sources, as defined. In advance of a federal portfolio standard and Senate Bill 251, SIGECO received regulatory approval to purchase a 3 MW landfill gas generation facility from a related entity. The facility was purchased in 2009 and is directly connected to the Company's distribution system. In 2008 and 2009, the Company executed long-term purchase power commitments for a total of 80 MW of wind energy. The Company currently has approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investment.

Manufactured Gas Plants
In the past, the Company operated facilities to manufacture natural gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under current environmental laws and regulations, those that owned or operated these facilities may now be required to take remedial action if certain contaminants are found above the regulatory thresholds.

In the Indiana Gas service territory, the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which the Company may have some remedial responsibility. A remedial investigation/feasibility study (RI/FS) was completed at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's Voluntary Remediation Program (VRP). The Company has identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. The Company is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it has incurred or reasonably expects to incur totaling approximately $42.4 million ($23.2 million at Indiana Gas and $19.2 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. Likewise, SIGECO has settlement agreements with all known insurance carriers and has received to date approximately $14.2 million of the expected $15.7 million in insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of September 30, 2013 and December 31, 2012, approximately $5.1 million and $4.6 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

Results of Operations of the Nonutility Group

The Nonutility Group operates in three primary business areas: Infrastructure Services, Energy Services, and Coal Mining. Infrastructure Services provides underground pipeline construction and repair. Energy Services provides performance contracting and renewable energy services. Coal Mining owns, and through its contract miners, mines and then sells coal. There are also other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. The Nonutility Group supports the Company's regulated utilities by providing infrastructure services and coal. Prior to June 18, 2013, the Company, through Enterprises, was involved in nonutility activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance. Pursuant to service contracts, Energy Marketing provided the Company's regulated utilities natural gas supply services. Nonutility Group earnings, excluding the results from ProLiance, for the three and nine months ended September 30, 2013 and 2012 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share amounts)	2013	2012	2013	2012
NET INCOME EXCLUDING PROLIANCE RESULTS	$17.5	$15.6	$19.9	$27.6
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING PROLIANCE RESULTS	$0.21	$0.18	$0.24	$0.33
NET INCOME (LOSS) ATTRIBUTED TO:				
Infrastructure Services	$20.4	$15.9	$35.2	$27.3
Energy Services	0.2	2.6	(2.0)	0.9
Coal Mining	(2.3)	(2.2)	(12.0)	—
Other Businesses	(0.8)	(0.7)	(1.3)	(0.6)

Including the results from ProLiance, the Nonutility Group results were earnings of $17.5 million and $13.2 million for the three months ended September 30, 2013 and 2012, and a net loss of $17.6 million and net income of $14.1 million for the nine months ended September 30, 2013 and 2012.

Infrastructure Services

Infrastructure Services provides underground pipeline construction and repair services through wholly-owned subsidiaries Miller Pipeline, LLC (Miller) and Minnesota Limited, LLC (Minnesota Limited). Inclusive of holding company costs, earnings from Infrastructure Services' operations for the third quarter of 2013 were $20.4 million, compared to $15.9 million for the same period in the prior year. During the nine months ended September 30, 2013, earnings were $35.2 million, compared to $27.3 million year to date in 2012. The increased earnings in both the quarter and year to date periods reflect continued increased demand for services. Revenues year to date in 2013 were $581 million, compared to revenues of $449 million in the prior year. Construction activity generally is expected to remain strong as utilities and municipalities replace their aging natural gas and oil infrastructure. In addition, construction activity is expected to be favorably impacted as pipeline operators construct new pipelines and related infrastructure due to the continued strong demand for shale gas and oil infrastructure.

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Energy Services

Energy Services provides energy performance contracting and renewable energy services through wholly-owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' earnings were $0.2 million during the third quarter of 2013, compared to earnings of $2.6 million during the third quarter of 2012. During the nine months ended September 30, 2013, Energy Services' operated at a loss of $2.0 million, compared to earnings of $0.9 million in 2012.

The lower results in both the quarter and year to date periods reflect lower revenues, which indicates continued slowness in demand for performance contracting projects due primarily to budgetary constraints at state, municipal, and school customers. The unfavorable impact to results in both the quarter and year to date periods was partially offset by increased tax deductions associated with energy efficiency projects in accordance with IRS guidance released in 2012. At September 30, 2013, performance contracting backlog was $65 million, compared to $77 million on December 31, 2012. ESG continues to develop strategies to position it for growth as the national focus on energy conservation, renewable energy, and sustainability continues for the long-term given the expected rise in power prices across the country.

Coal Mining

Coal Mining owns, and through its contract miners, mines and then sells coal to the Company’s utility operations and to third parties through its wholly-owned subsidiary Vectren Fuels, Inc. (Vectren Fuels). Results from Coal Mining, inclusive of holding company costs, were a loss of $2.3 million in the third quarter of 2013, about flat to the same period in the prior year. Year to date in 2013, Coal Mining results were a loss of $12.0 million, compared to break-even results in the prior year.

While coal sales and related revenues were higher in 2013 as compared to the prior year due to additional volumes sold, year to date results in 2013 were lower due to continued higher production costs associated with a thin coal seam and other unfavorable mining conditions at Prosperity mine. While additional improvement measures are still being implemented, substantial progress was made in the third quarter of 2013 in the execution of the revised mining plan, resulting in significant improvement in the production costs at Prosperity mine during the quarter. Results during the quarter and year to date periods also reflect reduced pricing for customers associated with contracts that had price reopener clauses during 2012 and the overall softness in the coal market.

Vectren Fuels' expected production is approximately 6.2 million tons in 2013. Coal sales in 2013 are estimated at 6.5 million tons. The Company's second mine at its Oaktown mining complex began production during the second quarter of 2013. Oaktown 1 is producing at costs that are very competitive and Oaktown 2 production costs are expected to be similar once the production ramp up is complete. To date, mining conditions and production costs at the Company's Oaktown mining complex are in line with expectations.

Coal Reserves
As of September 30, 2013, management estimates the Company’s total Illinois Basin coal reserves to be approximately 123 million tons. Once the Company's second mine at its Oaktown mining complex is in full production, Vectren Fuels underground mines are capable of producing about 7.5 million tons of coal per year.

Mine Safety Information
The Company retains independent third party contract mining companies to operate its coal mines. Five Star Mining LLC ("Five Star") is the contract mining company at the Prosperity underground mine and Black Panther Mining LLC ("Black Panther") is the contract mining company at the Oaktown underground mines. The contract mining companies are the mine “operator”, as that term is used in both the Federal Mine Safety and Health Act of 1977 (the

"Mine Act") and the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. All employees at the coal mines are hired, supervised, and paid by the contract mining companies. As the mine operator, the contract mining companies make all regulatory filings required by the MSHA. In most circumstances, however, the cost of fines and penalties assessed by MSHA are contractually passed through from the contract mining company to Vectren Fuels. The process of settling such claims can take years in certain circumstances. During the nine months ended September 30, 2013, the Company paid approximately $0.4 million related to assessments issued to the mine operators.

More detailed information about the Company’s mines, including safety-related data, can be found at MSHA’s website, www.MSHA.gov. Prosperity operates under the MSHA identification number 1202249; Oaktown 1 operates under the identification number 1202394; and Oaktown 2 operates under the identification number 1202418. Mine safety-related data included on the MSHA website is influenced by the size of the mine, the level of activity at the mine, and the mine inspector’s judgment, among other factors. These factors can impact the comparability of information from mine to mine and time period to time period.

A significant increase in the frequency and scope of MSHA inspections continues generally. Over the twelve month period ended September 30, 2013 and as a direct result of continued focus on safe work practices, citations issued by MSHA at Prosperity mine decreased over 30 percent. On October 11, 2013, a Prosperity mine contract employee was fatally injured. On October 23 and October 29, 2013, there were a significant number of unwarrantable failure citations written at Prosperity mine. Through the contract miner and consistent with past practice, the Company intends to fully evaluate the citations written, including the likely challenge of the basis for each citation. The process of review, challenge and resolution of any assessment could be lengthy. However, MSHA no longer is required to wait for final orders of citations before relying on those citations to place a mine on a Pattern of Violation (POV) status, and the initial step of notifying mine operators and allowing time to reduce instances of violations has been eliminated. Though not indicated at this time, in the future if Prosperity mine were placed on POV status, any future elevated citation written would result in the affected area of the mine being temporarily shut down until the issue causing the citation is resolved. While under POV status, citations written would result in more frequent shutdowns of portions or all of the mine, resulting in higher costs of production.

ProLiance Results

The Company has an investment in ProLiance, a nonutility affiliate of Vectren and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance exited the natural gas marketing business through the disposition of certain of the net assets of its energy marketing business, ProLiance Energy, LLC (ProLiance Energy). ProLiance Energy provided services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance Energy's customers included, among others, Vectren's Indiana utilities as well as Citizens' utilities. Consistent with its ownership percentage, Vectren is allocated 61 percent of ProLiance’s profits and losses; however, governance and voting rights remain at 50 percent for each member; and therefore, the Company accounts for its investment in ProLiance using the equity method of accounting.

Vectren Energy Marketing and Services, Inc (EMS), a wholly owned subsidiary, holds the Company’s investment in ProLiance. EMS is responsible for certain financing costs associated with ProLiance and is also responsible for income taxes and allocated corporate expenses related to the Company’s portion of ProLiance’s results. During the third quarter ended September 30, 2012, EMS results related to the Company’s share of ProLiance’s results, which include financing costs, income taxes, and other holding company costs and inclusive of the loss associated with exiting the business as discussed below, were a loss of $2.4 million. During the nine months ended September 30, 2013, results at EMS related to ProLiance were a loss of $37.5 million, compared to a loss of $13.5 million in 2012.

As disclosed during the first quarter of 2013, analysis and evaluation of strategic alternatives related to the Company's investment in ProLiance were ongoing. On June 18, 2013, ProLiance exited the natural gas marketing business by disposing of certain of the net assets, along with the long-term pipeline and storage commitments, of its gas marketing subsidiary, ProLiance Energy to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). As a result of this transaction and subject to a final reconciliation of working capital, the Company recorded its share of the loss on the disposition, termination of long-term pipeline and storage commitments, and related transaction and other costs totaling $43.6 million pre-tax, or $26.8 million net of tax, during the second quarter of 2013. ProLiance funded an estimated equity shortfall at ProLiance Energy of $16.6 million at the time of the sale. To fund this estimated shortfall, the Company issued a note to ProLiance for its 61 percent ownership share of the $16.6 million shortfall, or $10.1

million, which was utilized by ProLiance to invest additional equity in ProLiance Energy. This interest-bearing note is classified as Other nonutility investments in the Condensed Consolidated Balance Sheets. After consideration of cash generated from the tax benefit of losses, the net impact on cash to the Company is generally neutral. In addition to the losses associated with the disposition of certain of the net assets, the Company recorded its share of operating losses from ProLiance totaling $10.7 million, net of tax, for the year to date period.

As part of the transaction discussed above, ProLiance filed two petitions with the FERC seeking waivers of certain capacity release regulations. Under the first petition ProLiance sought to permanently release pipeline capacity to ETC that is used to provide service to retail customers. Under the second petition, ProLiance sought the same type of waiver in order to permanently release back to the utilities the pipeline contracts used to provide supply services to the utilities. The FERC has granted both requested waivers. ETC has taken assignment of the Portfolio Administration Agreements (PAAs) pursuant to which the utilities receive gas supply. With the receipt of the FERC waivers and with pipeline contracts having been transferred to the utilities, the utilities entered into an Asset Management Agreement (AMA) with ETC on September 1, 2013 and have temporarily released the pipeline contracts to ETC. ETC will fulfill the requirements of the PAAs through their remaining term ending in March 2016.

The amount recorded to Equity in (losses) of unconsolidated affiliates related to ProLiance's results totaled a pre-tax loss of $3.0 million for the three months ended September 30, 2012. For the nine months ended September 30, 2013 and 2012, the amounts recorded to Equity in (losses) of unconsolidated affiliates related to ProLiance's results totaled a pre-tax loss of $56.6 million and $17.1 million, respectively. At September 30, 2013, ProLiance had approximately $51.5 million of members' investment remaining on its balance sheet, supported by its investment in LA Storage, formerly named Liberty Gas Storage, LLC (Liberty) of $35.6 million, two midstream assets, and a small amount of working capital. The Company's remaining investment in ProLiance at September 30, 2013 totals $31.4 million and is comprised of $21.3 million of equity and a $10.1 million note receivable.

Investment in Liberty

Liberty, a joint venture between a subsidiary of ProLiance and a subsidiary of Sempra Energy (SE), is a development project for salt-cavern natural gas storage facilities. ProLiance is the minority member with a 25 percent interest, which it accounts for using the equity method. The project was expected to include 17 Bcf of capacity in its North site, and an additional capacity of at least 17 Bcf at the South site. The South site also has the potential for further expansion. The Liberty pipeline system is currently connected with several interstate pipelines, including the Cameron Interstate Pipeline operated by Sempra Pipelines & Storage, and will connect area liquefied natural gas regasification terminals to an interstate natural gas transmission system and storage facilities.

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, which resulted in Liberty recording a $132 million impairment charge. The Company, through ProLiance, recorded its share of the charge in 2009. As a result of the issues encountered at the North site, Liberty requested and the FERC approved the separation of the North site from the South site. Approximately 12 Bcf of the storage at the South site, which comprises three of the four FERC certified caverns, is fully tested but additional work is required to connect the caverns to the pipeline system. ProLiance's investment in Liberty is approximately $35.6 million.

Liberty received a demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") on February 8, 2011 related to a Sublease Agreement ("Sublease") between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of September 30, 2013, ProLiance has no material reserve recorded related to this matter and this litigation has not materially impacted ProLiance's results of operations or statement of financial position.

Impact of Recently Issued Accounting Guidance and Other Authoritative Guidance

Offsetting Assets and Liabilities

In January 2013, the FASB issued new accounting guidance on disclosures of offsetting assets and liabilities. This guidance amends prior requirements to add clarification to the scope of the offsetting disclosures. The amendment clarifies that the scope applies to derivative instruments accounted for in accordance with reporting topics on derivatives and hedging, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with US GAAP or subject to an enforceable master netting arrangement or similar agreement. This guidance is effective for fiscal years beginning on or after January 1, 2013 and interim periods within annual periods. The Company adopted this guidance as of January 1, 2013. The adoption of this guidance did not have a material impact on the Company's financial statements.

Accumulated Other Comprehensive Income (AOCI)

In February 2013, the FASB issued new accounting guidance on the reporting of reclassifications from AOCI. The guidance requires an entity to report the effect of significant reclassification from AOCI on the respective line items in net income if the amount being reclassified is required under US GAAP to be reclassified in its entirety to net income. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference to other disclosures required that provide additional details about these amounts. The new guidance is effective for fiscal years, and interim periods within annual periods, beginning after December 15, 2012. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the company's results of operations, cash flows or financial position.

Unrecognized Tax Benefit Presentation

In July 2013, the FASB issued new accounting guidance on presenting an unrecognized tax benefit when net operating loss carryforwards exist. The new standard was issued in an effort to eliminate diversity in practice resulting from a lack of guidance on this topic in the current US GAAP. The update provides that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except under certain circumstances outlined in the update. The amendments in the update are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, with early adoption permitted. This update is consistent with how the Company currently presents unrecognized tax benefits, therefore, adoption of this guidance resulted in no material impact on the Company's financial statements.

Final Federal Income Tax Regulations

In September 2013, the Internal Revenue Service (IRS) released final tangible property regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations are generally effective for tax years beginning on or after January 1, 2014, but may be adopted for 2013 tax years. Vectren intends to adopt the guidance for its 2014 tax year. The Company continues to evaluate the impact adoption of the regulations will have on its consolidated financial statements. As of this date, the Company does not expect the adoption of the regulations to have a material impact on its consolidated financial statements.

Financial Condition

Within Vectren's consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities, and short-term obligations outstanding at September 30, 2013 approximated $550 million and $73 million, respectively. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by its wholly owned subsidiaries and regulated utilities Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt, including current maturities, and short-term obligations outstanding at September 30, 2013 approximated $725 million and $176 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt, including current maturities, outstanding at September 30, 2013, approximated $382 million.

The Company’s common stock dividends are primarily funded by utility operations. Nonutility operations have demonstrated profitability and the ability to generate cash flows. These cash flows are primarily reinvested in other nonutility ventures, but are also used to fund a portion of the Company’s dividends, and from time to time may be reinvested in utility operations or used for corporate expenses.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at September 30, 2013, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor’s) and Moody’s Investors Service (Moody’s), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 48 percent of long-term capitalization at both September 30, 2013 and December 31, 2012, respectively. Long-term capitalization includes long-term debt, including current maturities, as well as common shareholders' equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of September 30, 2013, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A3 investment grade credit ratings have allowed it to access the capital markets as needed, and the Company believes it will have the ability to continue to do so. Given the Company's intent to maintain a balanced long-term capitalization ratio, it anticipates funding future capital expenditures and dividends principally through internally generated funds, which have recently been enhanced by bonus depreciation legislation, and refinancing maturing or callable debt using the capital markets. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline infrastructure replacement; coal mine safety; expanded EPA regulations for air, water, and fly ash; and growth of Infrastructure Services and Energy Services. These regulations may result in the need to raise additional capital in the coming years. In addition, the Company may expand its businesses through acquisitions and/or joint venture investments. The timing and amount of such investments depends on a variety of factors, including the availability of acquisition targets and available liquidity. The Company may also consider disposing of certain assets, investments, or businesses to enhance or accelerate internally generated cash flow.

Specifically for 2013, the Company has accessed the capital markets to refinance debt maturities or debt that is callable. During the second quarter of 2013, approximately $111 million of SIGECO's tax-exempt long-term debt was redeemed at par plus accrued interest. Approximately $62 million of tax-exempt long-term debt was reissued on April 26, 2013 at interest rates that are fixed to maturity, receiving proceeds, net of issuance costs, of approximately $60 million. The terms are $22.2 million at 4.00 percent per annum due in 2038, and $39.6 million at 4.05 percent per annum due in 2043.

The remaining approximately $49 million of the called debt was remarketed on August 13, 2013. The remarketed tax-exempt debt has a fixed interest rate of 1.95 percent per annum until September 13, 2017. SIGECO closed on this remarketing and received net proceeds of $48.3 million on August 28, 2013.

On April 1, 2013, VUHI executed an early redemption at par of $121.6 million 6.25 percent senior unsecured notes due in 2039. This debt was refinanced on June 5, 2013, with proceeds from a private placement note purchase agreement entered into on December 20, 2012, with a delayed draw feature. It provides for the following tranches of notes: (i) $45 million, 3.2 percent senior guaranteed notes, due June 5, 2028 and (ii) $80 million, 4.25 percent senior guaranteed notes, due June 5, 2043. Total proceeds received from these notes, net of issuance costs, were $44.8 million and $79.6 million, respectively. The notes are unconditionally guaranteed by Indiana Gas, SIGECO and VEDO.

On August 22, 2013, VUHI entered into a private placement note purchase agreement pursuant to which institutional investors have agreed to purchase $150 million of senior guaranteed notes with a fixed interest rate of 3.72 percent per annum, due December 5, 2023. The notes will be unconditionally guaranteed by Indiana Gas, SIGECO, and VEDO. The Company expects to receive net proceeds of $149.1 million from the issuance of the senior guaranteed notes, which will be used to refinance $100.0 million of 5.25 percent senior notes that matured August 1, 2013, for capital expenditures, and for general corporate purposes. Subject to the satisfaction of customary conditions precedent, the notes will be funded on or about December 5, 2013, as a result of the delayed draw feature.

On August 6, 2013, Vectren Capital entered into a $100 million three year term loan agreement. Loans under the term loan agreement bear interest at either a Eurodollar rate or base rate plus an additional margin which is based on the Company's credit rating. The proceeds from this debt transaction were used to repay short-term borrowings outstanding under Vectren Capital's credit facility. The loan agreement is guaranteed by Vectren Corporation and includes customary representations, warranties, and covenants, including a leverage covenant consistent with leverage covenants contained in other Vectren Capital borrowing arrangements. The Company received net proceeds of approximately $100 million in August 2013.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2013, the Company has $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly-owned Nonutility Group and corporate operations. As reduced by borrowings currently outstanding, approximately $174 million was available for the Utility Group operations and approximately $177 million was available for the wholly-owned Nonutility Group and corporate operations. Both Vectren Capital’s and Utility Holdings’ short-term credit facilities are available through September 2016. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

The Company has historically funded the short-term borrowing needs of Utility Holdings’ operations through the commercial paper market and expects to use the Utility Holdings short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2013	2012	2013	2012
As of September 30				
Balance Outstanding	$176.1	$100.1	$73.1	$216.1
Weighted Average Interest Rate	0.31%	0.46%	1.30%	1.42%
Nine Months Ended September 30 Average				
Balance Outstanding	$121.4	$69.5	$136.4	$149.2
Weighted Average Interest Rate	0.35%	0.48%	1.36%	1.46%
Maximum Month End Balance Outstanding	$176.1	$100.1	$173.8	$216.1
Quarterly Average - September 30				
Balance Outstanding	$153.8	$63.8	$104.2	$204.2
Weighted Average Interest Rate	0.34%	0.47%	1.33%	1.47%
Maximum Month End Balance Outstanding	$176.1	$100.1	$152.8	$216.1

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances added additional liquidity of $5.3 million and $5.6 million in the nine months ended September 30, 2013 and 2012, respectively.

Potential Uses of Liquidity

Pension Funding Obligations

Management currently estimates contributing approximately $10 million to qualified pension plans in 2013, with contributions totaling $7.5 million in the nine months ended September 30, 2013.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly-owned subsidiaries. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary obligations in order to allow those subsidiaries the flexibility to conduct business without posting other forms of collateral. At September 30, 2013, parent level guarantees support a maximum of $25 million of ESG’s performance contracting commitments and warranty obligations and $45 million of other project guarantees. The broader scope of ESG’s performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $26 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $19 million represent letters of credit supporting other nonutility operations. As disclosed in Note 7 to the consolidated financial statements, a guarantee issued and outstanding to an unrelated party in connection with ProLiance's disposition of certain of the net assets of ProLiance Energy totaled $18.3 million at September 30, 2013. Although there can be no assurance that these guarantees will not be called upon, the Company believes that the likelihood the Company will be called upon to satisfy any obligations pursuant to these guarantees is remote.

Performance Guarantees & Product Warranties

In the normal course of business, wholly owned subsidiaries, including ESG, issue performance bonds or other forms of assurance that commit them to timely install infrastructure, operate facilities, pay vendors or subcontractors, and/or support warranty obligations. Based on a history of meeting performance obligations and installed products operating effectively, no significant liability or cost has been recognized for the periods presented.

Specific to ESG, in its role as a general contractor in the performance contracting industry, at September 30, 2013, there are 53 open surety bonds supporting future performance. The average face amount of these obligations is $4.7 million, and the largest obligation has a face amount of $57.3 million. The maximum exposure from these obligations is limited by the level of work already completed and guarantees issued to ESG by various subcontractors. At September 30, 2013, approximately 43 percent of work was completed on projects with open surety bonds. A significant portion of these open surety bonds will be released within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of September 30, 2013. In addition, ESG has an $8 million stand-alone letter of credit facility and as of September 30, 2013, $3.4 million was drawn upon and outstanding.

Other Letters of Credit

As of September 30, 2013, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at September 30, 2013.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $100 million for the remainder of 2013. Nonutility capital expenditures and investments are estimated at $70 million for the remainder of 2013.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $388.9 million and $293.8 million for the nine months ended September 30, 2013 and 2012, respectively. Approximately $52 million of the increase was due to a greater level of cash utilized from working capital in 2012, primarily related to the rising coal inventory at Vectren Fuels during that period. During the current year, coal inventory balances at Vectren Fuels have decreased, leading to favorable cash flow impacts. The change in noncurrent assets was primarily driven by the deferral for future recovery of certain coal costs pursuant to a regulatory order in the prior year. In addition, contributions to benefit plans were $6.0 million lower during 2013 compared to 2012.

Financing Cash Flow

Net cash flow required for financing activities was $119.8 million during the nine months ended September 30, 2013 compared to requirements of $29.3 million in 2012. Incremental long-term debt in the prior year resulted in lower cash requirements than the current year. Financing activity in both periods presented reflects the payment of dividends and the repayment of short-term borrowings.

Investing Cash Flow

Cash flow required for investing activities was $279.3 million and $266.1 million during the nine months ended September 30, 2013 and 2012, respectively. The primary use of cash in both periods presented reflect expenditures for utility and nonutility capital expenditures.

Forward-Looking Information

A “safe harbor” for forward-looking statements is provided by the Private Securities Litigation Reform Act of 1995 (Reform Act of 1995). The Reform Act of 1995 was adopted to encourage such forward-looking statements without the threat of litigation, provided those statements are identified as forward-looking and are accompanied by meaningful cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Certain matters described in Management’s Discussion and Analysis of Results of Operations and Financial Condition are forward-looking statements. Such statements are based on management’s beliefs, as well as assumptions made by and information currently available to management. When used in this filing, the words “believe”, “anticipate”, “endeavor”, “estimate”, “expect”, “objective”, “projection”, “forecast”, “goal”, “likely”, and expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.
- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, terrorist acts, cyber attacks, or other similar occurrences could adversely affect Vectren’s facilities, operations, financial condition and results of

operations.

- Increased competition in the energy industry, including the effects of industry restructuring, unbundling, and other sources of energy.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional regulation, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state

entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.

- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including increased potential for lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, coal, and other nonutility products and services; impacts on both gas and electric large customers; lower residential and commercial customer counts; higher operating expenses; and further reductions in the value of certain nonutility real estate and other legacy investments.
- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.
- Direct or indirect effects on the Company’s business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- The performance of projects undertaken by the Company’s nonutility businesses and the success of efforts to realize value from, invest in and develop new opportunities, including but not limited to, the Company’s infrastructure services, energy services, coal mining, and remaining energy marketing businesses and/or assets.
- Factors affecting infrastructure services, including the level of success in bidding contracts; fluctuations in volume of contracted work; unanticipated cost increases in completion of the contracted work; funding requirements associated with multi-employer pension plans; changes in legislation and regulations impacting the industries in which the customers served operate; the effects of weather; failure to properly estimate the cost to construct projects; the ability to attract and retain qualified employees in a fast growing market where skills are critical; cancellation and/or reductions in the scope of projects by customers; credit worthiness of customers; ability to obtain materials and equipment required to perform services; and changing market conditions.
- Factors affecting coal mining operations and their cost structure, including MSHA guidelines and interpretations of those guidelines, as well as additional mine regulations and more frequent and broader inspections that could result from mining incidents at coal mines; geologic conditions, including coal seam thickness, equipment, and operational risks; the ability to execute and negotiate new sales contracts and resolve contract interpretations; volatile coal market prices and demand; supplier and contract miner performance; the cost of production; the availability of key equipment, contract miners and commodities; availability of transportation; coal quality, including its sulfur and mercury content; and the ability to access coal reserves.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as mergers, acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, pipeline safety regulations, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of changes in actual results, changes in assumptions, or other factors affecting such statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the use of derivatives. The Company executes derivative contracts in the normal course of operations while buying and selling commodities and occasionally when managing interest rate risk.

The Company has in place a risk management committee that consists of senior management as well as financial and operational management. The committee is actively involved in identifying risks as well as reviewing and authorizing risk mitigation strategies.

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2012 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended September 30, 2013, there have been no changes to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of September 30, 2013, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of September 30, 2013, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and
2) accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

PART II

ITEM 1. LEGAL PROCEEDINGS

The Company is party to various legal proceedings and audits and reviews by taxing authorities and other government agencies arising in the normal course of business. In the opinion of management, there are no legal proceedings or other regulatory reviews or audits pending against the Company that are likely to have a material adverse effect on its financial position, results of operations, or cash flows. See the notes to the consolidated financial statements regarding commitments and contingencies, environmental matters, and rate and regulatory matters. The condensed consolidated financial statements are included in Part 1 Item 1.

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company's operating results and financial condition, causing them to be materially adversely affected. The Company's risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2012 Form 10-K and are therefore not presented herein.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company's share-based compensation plans. The following chart contains information regarding open market purchases made by the Company to satisfy share-based compensation requirements during the quarter ended September 30, 2013.

Period	Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares That May Be Purchased Under These Plans
July 1-31	22,000	$37.23	—	—
August 1-31	315,700	36.14	—	—
September 1-30	2,000	32.64	—	—

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable

ITEM 6. EXHIBITS

Exhibits and Certifications

10.1	Vectren Corporation Specimen Waiver, effective October 3, 2013, to the Vectren Corporation Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (filed herewith, as Exhibit 10.1). The specimen waiver is the same for all the named executive officers: Messer's Carl L. Chapman, Jerome A. Benkert, Jr., Ronald E. Christian, and William S. Doty.
31.1	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer
31.2	Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer
32	Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002
101	Interactive Data File
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VECTREN CORPORATION
Registrant

November 8, 2013

/s/Jerome A. Benkert, Jr.
Jerome A. Benkert, Jr.
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/M. Susan Hardwick
M. Susan Hardwick
Senior Vice President, Finance and Assistant Treasurer
(Principal Accounting Officer)

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