VECTREN CORP
Form 10-Q
November 07, 2014

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, 2014

OR

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

For the transition period from __________________ to __________________

Commission file number: 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 o 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 o 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 o
Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
o 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	82,537,902	October 31, 2014
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 Evansville, Indiana 47708	(812) 491-4000	Robert L. Goocher Treasurer and Vice President, Investor Relations vvcir@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, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash & cash equivalents	$8.4	$21.5
Accounts receivable - less reserves of $6.0 & $6.8, respectively	189.9	259.2
Accrued unbilled revenues	82.8	134.2
Inventories	114.8	134.4
Recoverable fuel & natural gas costs	25.5	5.5
Prepayments & other current assets	71.2	75.6
Total current assets	492.6	630.4
Utility Plant		
Original cost	5,599.2	5,389.6
Less: accumulated depreciation & amortization	2,250.3	2,165.3
Net utility plant	3,348.9	3,224.3
Investments in unconsolidated affiliates	24.4	24.0
Other utility & corporate investments	37.0	38.1
Other nonutility investments	34.4	33.8
Nonutility plant - net	372.3	657.2
Goodwill - net	289.9	262.3
Regulatory assets	193.8	193.4
Other assets	44.0	39.1
TOTAL ASSETS	$4,837.3	$5,102.6

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, 2014	December 31, 2013
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$172.2	$227.2
Refundable fuel & natural gas costs	—	2.6
Accrued liabilities	187.4	182.1
Short-term borrowings	62.4	68.6
Current maturities of long-term debt	5.0	30.0
Total current liabilities	427.0	510.5
Long-term Debt - Net of Current Maturities	1,572.3	1,777.1
Deferred Credits & Other Liabilities		
Deferred income taxes	671.7	707.4
Regulatory liabilities	404.8	387.3
Deferred credits & other liabilities	180.5	166.0
Total deferred credits & other liabilities	1,257.0	1,260.7
Commitments & Contingencies (Notes 7, 11-13)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 82.5 & 82.4 shares, respectively	714.7	709.3
Retained earnings	867.1	845.7
Accumulated other comprehensive (loss)	(0.8)	(0.7)
Total common shareholders' equity	1,581.0	1,554.3
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$4,837.3	$5,102.6

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 INCOME
(Unaudited – in millions, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
OPERATING REVENUES				
Gas utility	$105.1	$101.9	$681.1	$555.8
Electric utility	165.9	165.8	480.9	470.0
Nonutility	324.6	311.9	772.9	785.4
Total operating revenues	595.6	579.6	1,934.9	1,811.2
OPERATING EXPENSES				
Cost of gas sold	28.8	27.5	343.4	235.4
Cost of fuel & purchased power	50.3	50.4	155.4	154.5
Cost of nonutility revenues	112.4	107.7	259.7	271.4
Other operating	245.6	227.5	701.1	652.5
Depreciation & amortization	61.4	70.7	211.0	205.7
Taxes other than income taxes	12.6	12.5	46.9	43.7
Total operating expenses	511.1	496.3	1,717.5	1,563.2
OPERATING INCOME	84.5	83.3	217.4	248.0
OTHER INCOME (EXPENSE)				
Equity in earnings (losses) of unconsolidated affiliates	0.3	(0.3)	0.4	(57.6)
Other income – net	7.3	2.5	15.8	9.0
Total other income (expense)	7.6	2.2	16.2	(48.6)
INTEREST EXPENSE	21.7	21.3	65.7	66.3
INCOME BEFORE INCOME TAXES	70.4	64.2	167.9	133.1
INCOME TAXES	23.1	21.4	57.5	46.3
NET INCOME	$47.3	$42.8	$110.4	$86.8
AVERAGE COMMON SHARES OUTSTANDING	82.5	82.3	82.5	82.3
DILUTED COMMON SHARES OUTSTANDING	82.5	82.4	82.5	82.4
EARNINGS PER SHARE OF COMMON STOCK:				
BASIC	$0.57	$0.52	$1.34	$1.05
DILUTED	$0.57	$0.52	$1.34	$1.05
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.360	$0.355	$1.080	$1.065

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,	
	2014	2013	2014	2013
Net income	$47.3	$42.8	$110.4	$86.8
Other comprehensive income (OCI) of unconsolidated affiliates				
Net amount arising during the year before tax	—	0.1	—	4.6
Income taxes related to items of other comprehensive income	—	—	—	(1.8)
AOCI of unconsolidated affiliates, net of tax	—	0.1	—	2.8
Remeasurement of pension benefit obligation	—	—	(0.1)	—
Total comprehensive income	$47.3	$42.9	$110.3	$89.6

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, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$110.4	$86.8
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	211.0	205.7
Deferred income taxes & investment tax credits	(9.4)	32.4
Equity in (earnings)/losses of unconsolidated affiliates	(0.4)	57.6
Provision for uncollectible accounts	5.3	4.8
Expense portion of pension & postretirement benefit cost	5.1	6.7
Other non-cash charges - net	4.0	5.9
Loss on sale of business	41.8	—
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	101.9	56.3
Inventories	(18.8)	20.2
Recoverable/refundable fuel & natural gas costs	(22.6)	5.8
Prepayments & other current assets	(8.3)	0.8
Accounts payable, including to affiliated companies	(62.5)	(58.4)
Accrued liabilities	(1.7)	(15.0)
Unconsolidated affiliate dividends	—	0.3
Employer contributions to pension & postretirement plans	(3.5)	(10.1)
Changes in noncurrent assets & investments	(7.0)	(12.3)
Changes in noncurrent liabilities	(1.6)	1.4
Net cash provided by operating activities	343.7	388.9
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Long-term debt, net of issuance costs	63.0	332.7
Dividend reinvestment plan & other common stock issuances	4.7	5.3
Requirements for:		
Dividends on common stock	(89.1)	(87.6)
Retirement of long-term debt	(293.6)	(338.6)
Other financing activities	0.1	(2.0)
Net change in short-term borrowings	(6.2)	(29.6)
Net cash used in financing activities	(321.1)	(119.8)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Sale of business	319.8	—
Other collections	3.6	5.0
Requirements for:		
Transaction costs for sale of business	(8.9)	—
Capital expenditures, excluding AFUDC equity	(321.6)	(273.9)
Business acquisition	(28.6)	—
Other investments	—	(10.4)

Net cash used in investing activities	(35.7)	(279.3)
Net change in cash & cash equivalents	(13.1)	(10.2)
Cash & cash equivalents at beginning of period	21.5	19.5
Cash & cash equivalents at end of period	$8.4	$9.3

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), Southern Indiana Gas and Electric Company (SIGECO), 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 574,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 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 313,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business area. Results in the financial statements include the results of Vectren Fuels, Inc. (Vectren Fuels) through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. Further, prior to June 18, 2013, the Company had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). 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 (ProLiance Energy). Other minor operating results of the remaining ProLiance investment are reflected in Other Businesses. Enterprises 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.

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, 2013, filed with the Securities and Exchange Commission on February 20, 2014, 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. 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)	2014	2013	2014	2013
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$47.3	$42.8	$110.4	$86.8
Denominator:				
Weighted average common shares outstanding (Denominator for Basic EPS)	82.5	82.3	82.5	82.3
Conversion of share based compensation arrangements	0.0	0.1	0.0	0.1
Adjusted weighted average shares outstanding and assumed conversions outstanding (Denominator for Diluted EPS)	82.5	82.4	82.5	82.4
Basic EPS	$0.57	$0.52	$1.34	$1.05
Diluted EPS	$0.57	$0.52	$1.34	$1.05

For the three and nine months ended September 30, 2014 and 2013, all options and equity based instruments were dilutive and immaterial.

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 $4.9 million and $4.8 million in the three months ended September 30, 2014 and 2013, respectively, as a component of operating revenues. During the nine months ended September 30, 2014 and 2013, these taxes totaled $23.3 million and $20.9 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."

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)	2014	2013	2014	2013
Service cost	$1.8	$2.2	$0.1	$0.2
Interest cost	3.8	3.6	0.6	0.5
Expected return on plan assets	(5.6)	(5.6)	—	—
Amortization of prior service cost	0.3	0.4	(0.7)	(0.8)
Amortization of transitional obligation	—	—	—	—
Amortization of actuarial loss	1.3	2.6	0.1	0.1
Settlement charge	—	—	—	—
Net periodic benefit cost	$1.6	$3.2	$0.1	$—

	Nine Months Ended September 30,			
	Pension Benefits		Other Benefits	
(In millions)	2014	2013	2014	2013
Service cost	$5.5	$6.5	$0.3	$0.4
Interest cost	11.7	11.0	1.7	1.5
Expected return on plan assets	(17.1)	(16.6)	—	—
Amortization of prior service cost	0.8	1.1	(2.2)	(2.4)
Amortization of transitional obligation	—	—	—	—
Amortization of actuarial loss	3.7	7.6	0.3	0.5
Settlement charge	2.6	—	—	—
Net periodic benefit cost	$7.2	$9.6	$0.1	$—

Lump Sum Settlements

In 2013, the Company modified its three defined benefit pension plans to allow participants to elect a lump sum withdrawal of benefits. Such elections have been made in all plans by plan participants in 2013 and 2014. In one plan the significance of the lump sum distributions triggered settlement accounting rules and required a remeasurement of that plan's obligation as of June 30, 2014, pursuant to generally accepted accounting principles. As a result, the Company recognized a $2.6 million pension settlement charge in the nine month period ended September 30, 2014.

The Company remeasured the pension obligation for that plan using a discount rate of 4.40 percent at the remeasurement date of June 30, 2014 compared to the discount rate used at December 31, 2013 of 4.97 percent. This decrease in discount rate is the primary driver of a $5.1 million increase in the pension liability upon remeasurement. Of that amount, $5.0 million was recorded as an increase to Regulatory Assets, as the Company's retirement costs primarily relate to its regulated utilities, and the remaining $0.1 million was recorded as a decrease to other comprehensive income.

Employer Contributions to Qualified Pension Plans

Currently, the Company anticipates making no contributions to its qualified pension plans in 2014.

6. Supplemental Cash Flow Information

As of September 30, 2014 and December 31, 2013, the Company has accruals related to utility and nonutility plant purchases totaling approximately $20.8 million and $19.4 million, respectively.

7. Investment in ProLiance Holdings, LLC

The Company has an investment in ProLiance Holdings, an affiliate of the Company 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, to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). Other minor operating results of the remaining ProLiance investment are reflected in Other Businesses. The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). 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, 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. At the time of the sale, ProLiance Holdings funded an estimated equity shortfall at ProLiance Energy of $16.6 million. To fund this estimated shortfall, the Company issued a note to ProLiance Holdings for its 61 percent ownership share of the $16.6 million shortfall, or $10.1 million, which was utilized by ProLiance Holdings to invest additional equity in ProLiance Energy. This interest-bearing note is classified as Other nonutility investments in the Condensed Consolidated Balance Sheets.

The Company's remaining investment in ProLiance at September 30, 2014 is as follows and reflects that it relates primarily to an investment in LA Storage discussed below:

(In millions)	As of September 30, 2014
ProLiance Energy	$1.2
Midstream assets and cash from sale of storage assets	7.8
LA Storage	21.7
Total investment in ProLiance	$30.7
Included in:	
Investments in unconsolidated affiliates	$20.6
Other nonutility investments	$10.1

LA Storage, LLC Storage Asset Investment

ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. The project is expected to include 17 Bcf of capacity, and has the potential for further expansion. This 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.

Approximately 12 Bcf of the storage, 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. The timing and extent of development of these caverns is dependent on market conditions, including pricing, need for storage capacity, and development of the liquefied natural gas market, among other factors. As of September 30, 2014 and December 31, 2013, ProLiance's investment in the joint venture was $35.6 million and $35.4 million, respectively.

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. ("Williams") in February 2011 related to a sublease agreement. Williams alleges that the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of September 30, 2014, 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
The Company had no purchases from ProLiance for resale and for injections into storage for the three and nine months ended September 30, 2014, as a result of ProLiance exiting the natural gas marketing business. For the three months ended September 30, 2013, the Company had no purchases, and for the nine months ended September 30, 2013 purchases totaled $200.5 million. The Company did not have any amounts owed to ProLiance for purchases at September 30, 2014 or at December 31, 2013.

8. Federal Business Unit Acquisition

On April 1, 2014, the Company, through its wholly-owned subsidiary Energy Systems Group (ESG), purchased the federal sector energy services unit of Chevron Energy Solutions (CES) from Chevron USA, referred to hereafter as the Federal Business Unit or FBU. FBU performs under several long-term operations and maintenance contracts (O&M), and has a construction project sales funnel. Included in the acquisition are several Indefinite Delivery / Indefinite Quantity contracts with federal government entities including Energy Savings Performance Contracts (ESPC) with the US Department of Energy and US Army Corps of Engineers. Also included are long-term operation and maintenance and repair contracts with multiple Department of Defense installations. FBU is included in the Company’s nonutility Energy Services operating segment.

See further discussion of Company issued guarantees and a Vectren Enterprises’ indemnification associated with this acquisition in Footnote 11.

The base purchase price was approximately $19.7 million in cash, which included a working capital amount of $1.2 million. The total purchase price is expected to be approximately $45 million, or $42.1 million on a net present value basis. The purchase price includes additional cash payments made in July of approximately $8.9 million related to specific contract transfers and $13.5 million as the net present value of contingent consideration related to new order targets in 2014 and 2015. The contingent consideration is subject to separate earn-out thresholds for orders in 2014 and 2015, the first of which is a threshold of $50 million in orders before the end of 2014. If $50 million in orders are not reached before the end of 2014, the contingent consideration will not be earned. If $50 million in orders are signed in 2014 and an aggregate of $200 million or more of orders are signed through 2015, the full amount of the contingent consideration will be paid.

The Company recognized the assets acquired and the liabilities assumed, measured at their fair values as of the date of acquisition. The following table summarizes the allocation of the purchase price to the fair value of the assets acquired and liabilities assumed as of April 1, 2014.

(In millions)	
Adjusted Net Working Capital	$2.2
Depreciable Fixed Assets	0.4
Customer Relationships (Sales Funnel)	7.1
ESPC Licenses	6.0
Deferred Tax Asset	0.8
Goodwill	27.7
Total Assets acquired	44.2
Less: Unfavorable Contract Liabilities Assumed	(2.1)
Total Purchase Consideration	$42.1

The purchase price and its allocation remain preliminary and are subject to possible adjustments in subsequent periods. Any subsequent material changes to the purchase price and its allocation will be adjusted pursuant to applicable accounting guidance.

Level 3 market inputs, such as discounted cash flows and revenue growth rates were used to derive the preliminary fair values of the identifiable intangible assets. Identifiable intangible assets include long-term customer relationships and licenses. Goodwill arising from the purchase represents intangible value the Company expects to realize over time. This value includes but is not limited to: 1) expected customer growth beyond what is in the current sales funnel and 2) the experience of the acquired work force. The goodwill, which does not amortize pursuant to accounting guidance, is deductible over a 15-year period for purposes of computing current income tax expense, and will be included in the Energy Services operating segment.

Transaction costs associated with the acquisition and expensed by the Company totaled approximately $1.7 million, of which $0.8 million are included in other operating expenses during the nine months ended September 30, 2014. For the period from April 1, 2014 through September 30, 2014, FBU contributed an immaterial amount of revenue and net loss to the Company's revenue and net income.
During the quarter ended September 30, 2014 and 2013, unaudited proforma results of the combined companies, assuming the acquisition closed on January 1, 2013, would have added an immaterial amount to consolidated revenues for both periods. For the nine months ended September 2014 and 2013, unaudited proforma results would have added approximately $12.3 million and $21.9 million to consolidated revenues, respectively. For the periods presented, the impact to net income and earnings per share would have been de minimis. These proforma results may not be indicative of what actual results would have been if the acquisition had taken place on the proforma date or of future results.

9. Sale of Vectren Fuels, Inc.

On July 1, 2014, the Company announced that it had reached an agreement to sell its wholly-owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Sunrise owns and operates coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. The cash received at closing was approximately $320 million, including $24 million as the change in working capital from December 31, 2013, through closing. The transaction is further subject to a final working capital settlement. At June 30, 2014, the Company recorded an estimated loss on transaction, including costs to sell, of approximately $32 million, or $20 million after tax. At September 30, 2014, the pre-tax loss of $32 million was reflected in the Condensed Consolidated Statement of Income as a $42 million charge to other operating expense, offset by $10 million in lower depreciation expense as depreciation ceased for the assets classified as held for sale at June 30, 2014. Results from Coal Mining for the quarter and year to date periods ended September 30, 2014, inclusive of the loss on sale, were losses of $2.1 million and $21.4 million, net of tax, respectively. For the prior year, results for Coal Mining were losses of $2.3 million and $12.0 million, for the quarter and year to date periods ended September 30, 2013, respectively.

10. Financing Activities

Vectren Capital Unsecured Note Retirement
On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

SIGECO Debt Refund and Issuance
On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4.00 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1,

2025, sold in a private placement at variable rates through September 2019.

Sale of Vectren Fuels Proceeds
On August 29, 2014, the Company closed on a transaction to sell its wholly-owned coal mining subsidiary, Vectren Fuels, to Sunrise. The proceeds received, net of transaction costs and estimated tax payments, totaled $291 million and were used to retire $200 million in outstanding Vectren Capital Corp (Vectren Capital) bank term loans and pay down outstanding short-term debt.

Short-term Credit Facilities
On October 31, 2014, Vectren Capital's and Utility Holdings' short-term credit facilities, totaling $600 million in borrowing capacity, were amended to extend their maturity until October 31, 2019.

11. Commitments & Contingencies

Commitments
The Company's regulated utilities have both firm and non-firm commitments to purchase natural gas, electricity, and coal as well as certain transportation and storage rights and certain contracts are firm commitments under five and ten year arrangements. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

Corporate Guarantees
The Company issues parent level guarantees to certain vendors and customers of its wholly-owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations, in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At September 30, 2014, parent level guarantees, excluding guarantees of obligations of the federal business unit acquired from Chevron USA on April 1, 2014, as further described below, 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.

On April 1, 2014, Energy Systems Group acquired the federal sector energy services unit of Chevron Energy Solutions, from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., the wholly-owned holding company for the Company's nonutility investments, provided CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG.

The acquisition also includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The Company guarantees ESG's performance under these energy savings guarantees. The total maximum amount of the energy savings guarantees is approximately $140 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. Further, an energy facility operated by ESG and managed by Keenan Ft Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

In addition, the Company has approximately $15 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $9 million represent letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions 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, 2014, there are 48 open surety bonds supporting future performance. The average face amount of these obligations is $6.0 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, 2014, approximately 46 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 accruals for these warranty and energy obligations as of September 30, 2014.

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.

12. Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

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 included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $132.9 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $12.1 million and $9.3 million at September 30, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million, subject to the DRR rate caps approved in the Order. In addition, the Order approved the Company's commitment that the DRR can only be further

extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rate, effective September 1, 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 deferral application under this law, reflecting its capital expenditure program covering the fifteen

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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 small general service customer per month. In addition, the Order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed above are not expected to be reached given the Company's capital expenditure plan during the remaining four year time frame.

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 Indiana Gas and $3 million annually at SIGECO. The debt-related post in service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At September 30, 2014 and December 31, 2013, the Company has regulatory assets totaling $15.3 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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 current 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 and recovered in the Company's next general rate case, which must be filed before the expiration of the seven year plan. 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.

While 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 Indiana Regulatory Mechanisms

The Company filed in November 2013 for authority to recover costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. On August 27, 2014, the Commission issued an Order approving the Company’s seven year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to the legislation. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses associated with pipeline safety rules, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines for the Company to update its seven year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. Finally, the Order approved the Company’s proposal to recover eligible costs via a fixed monthly rate per residential customer. On September 26, 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. The specific issues raised by the OUCC have not yet been identified. An appeal was filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of the NIPSCO appeal and its implications to the Company’s Order, if any, cannot be determined.

On October 1, 2014, the Company filed its initial request for approval of the revenue requirement associated with capital investment through June 30, 2014 as part of its approved infrastructure improvement plan. As the next step of the recovery process as outlined in the legislation, this filing, once approved, will initiate the rates necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also in this filing, consistent with the guidelines set forth in the Order, the Company submitted an update to its seven year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately $900 million, inclusive of an estimated $30 million of economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules. Pursuant to Senate Bill 560, the Company expects an order by the end of 2014.

Indiana Gas GCA Cost Recovery Issue

On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC has modified its position in testimony filed on November 5, 2014, and now supports a reduced disallowance of $3.0 million. The Company believes that the costs are either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a cost disallowance, any such loss would be allocated to its supply administrator. An order is expected in November 2014.

SIGECO Electric Environmental Compliance Filing

On January 17, 2014, SIGECO filed a request with the IURC for approval of capital investments estimated to be between $70 and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address the NOV on alleged increases in sulfur trioxide emissions. Although the Company believes these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investments under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. The accounting treatment request seeks deferral of depreciation and property tax expense related to these investments, accrual of post in service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The Company filed its case-in-chief on March 14, 2014. Intervening parties filed their testimony on May 28, 2014, to which the Company responded with rebuttal testimony on June 20, 2014. A hearing was held beginning on July 30, 2014. The case has been fully briefed as of October 2, 2014, and the Company is awaiting a Commission order.

Coal Procurement Procedures

SIGECO annually submits its coal procurement plan for IURC review in a sub docket proceeding. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to an affiliate of Sunrise Coal, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. The OUCC filed testimony in September 2014 in support of the reasonableness of these contracts. A hearing was held in October 2014 and the Company is awaiting an order from the Commission.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer’s rates effective February 1, 2012. The total balance deferred for recovery through the Company’s FAC, starting February 2014, was $42.4 million, of which $37.1 million remains as of September 30, 2014.

SIGECO Electric Demand Side Management Program Filing

On August 16, 2010, SIGECO filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 Order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC Order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an Order approving an initial three year DSM plan in the SIGECO electric service territory that complied with the IURC’s energy saving targets. Consistent with the Company’s proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the nine months ended September 30, 2014 and September 30, 2013, the Company recognized Electric revenue of $6.6 million and $3.5 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of July 1, 2014, approximately 71 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

Indiana Gas Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Indiana Gas alleging several violations of safety regulations pertaining to damage that occurred at a residence in Indiana Gas'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 was reached between the IURC's pipeline safety division and Indiana Gas that allowed Indiana Gas to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

Indiana Gas & SIGECO Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015. The Order provides that the companies must submit an extension proposal no later than March 1, 2015.

FERC Return on Equity Complaint

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners' rates, including SIGECO's formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of September 30, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $144.5 million at September 30, 2014.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving the 10.57 percent return on equity and the methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. If a settlement is not reached, the case will move to a formal evidentiary hearing before the FERC. The Company has established a reserve pending the outcome of this complaint.

13. Legislative & Environmental Matters

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251

Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company continues with its ongoing evaluation of 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 SO2 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 SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. On December 30, 2011, a reviewing 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 April 2014, the US Supreme Court upheld CSAPR. On June 26, 2014, the EPA asked the federal appeals court to lift the stay of the rule. EPA also asked the court to approve a new deadline schedule for entities that must comply, with the first phase caps starting in 2015 and 2016, and the second phase in 2017. On October 23, 2014 the Court granted the EPA's request to lift the CSAPR stay, but did not finalize the new implementation dates. While it is possible that the EPA could further revise the rule prior to implementation, the Company does not anticipate a significant impact from the Supreme Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air and Water 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). Multiple judicial challenges were filed, and the EPA agreed to reconsider MATS requirements for new construction, as the 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. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. In July a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

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 Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed with the IURC in the SIGECO Electric Environmental Compliance Filing.

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” (BTA) 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 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 was issued on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a case by case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company’s facilities. The Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The 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. The 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 Air and Water 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 SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. 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 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. Some operational modifications to the control equipment are likely. 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 $70 million and $90 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. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address the EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term. In July a hearing was held before the IURC in this matter. The case has been fully briefed as of October 2, 2014, and the Company is awaiting a Commission order.

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. Recently the EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

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 only 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 cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of 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, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously, and by June 2014 propose, and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO_2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO_2 emissions by 30 percent from 2005 levels by 2030. Unlike most rulemakings which allow for a 30 day public comment period, the EPA provided an initial 120 days from publication of the proposal in the Federal Register, and a subsequent extension of the public comment period was granted to December 1, 2014. The proposal sets state-specific CO_2 emission rate-based CO_2 goals (measured in lb CO_2/MWh or "megawatt hour") and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO_2/MWh, and sets an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units, or generating systems. They are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state's interim or "phase in" goal of 1,607 lb CO_2/MWh must be met as averaged over a ten year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state's mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana's total CO_2 emission rate compared to 2012. At 20 percent Indiana's CO_2 emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement in US. This is due in part to the EPA's attempt to recognize the existing generating resource mix in the state and take into account each state's ability to cost effectively lower its CO_2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state's goals were set by taking 2012 emissions data and applying four "building blocks" of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA's determination of "Best System of Emission Reductions that has been adequately demonstrated," which defines the EPA's authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state's existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO_2 emission rate. Despite having just been recently proposed and not expected to be finalized until June of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans.

With respect to the state of Indiana, the four building blocks that support Indiana's goal are as follows:

(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO_2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO_2 produced from electric generation. In 2013, Indiana's electric utilities generated 105.6 million tons of CO_2. The Company's share of that total was 6.3 million, or <6 percent. Since 2005, the Company's emissions of CO_2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to CO_2 emission rate, since 2005 the Company has lowered its CO_2 emission rate (as measured in lbs CO_2/MWh) from 1967 lbs CO_2/MWh to 1922 lbs CO_2/MWh, for a reduction of 3 percent. the Company's CO_2 emission rate of 1922 lbs/MWh is basically the same as the State's average CO_2 emission rate of 1923 lb CO_2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown

If the regulations referenced above are finalized by the EPA, 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 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 were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of

Indiana begins formulation of its state implementation plan, the Company will have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates 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 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Renewables
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 4 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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.3 million of the expected $15.8 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, 2014 and December 31, 2013, approximately $4.3 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

14. Impact of Recently Issued Accounting Principles

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.

Investments in Qualified Affordable Housing Projects

In January 2014, the FASB issued new accounting guidance on accounting for investments in qualified affordable housing projects. The amendments in this guidance allows an entity to make an accounting policy election to account for investments in qualified affordable housing projects using a proportional amortization method, if certain conditions are met. Under the election, the entity would amortize the initial cost of the investment in proportion to the tax credits and other benefits received while recognizing the net investment performance in the income statement as a component of income tax expense (benefit). The guidance is effective for annual periods and interim reporting periods within those annual periods, beginning after December 15, 2014, with early adoption permitted. The Company is assessing if its affordable housing investments will qualify for the election and whether or not it will choose to exercise the election. Adoption of this guidance will not have a material impact on the Company's financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company did not adopt this guidance in accounting for the sale of its Coal Mining assets as discussed in footnote 9. The Company is currently evaluating the impact of this guidance, if any.

Accounting for Stock Compensation

In June 2014, the FASB issued new accounting guidance on accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. These amendments provide explicit guidance on whether to treat a performance target that could be achieved after the requisite service period as a performance condition that affects vesting or as a non-vesting condition that affects the grant-date fair value of an award. This guidance is effective for annual periods and interim periods within those periods beginning after December 15, 2015, with early adoption permitted. The Company’s current practice for accounting for stock compensation follows the prescribed manner as suggested by the update. Adoption of this guidance will not have a material impact on the Company’s financial statements.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016, and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company’s financial statements.

15. Fair Value Measurements

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

(In millions)	September 30, 2014		December 31, 2013	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,577.3	$1,740.9	$1,807.1	$1,895.2
Short-term borrowings	62.4	62.4	68.6	68.6
Cash & cash equivalents	8.4	8.4	21.5	21.5

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 nature of certain other 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, 2014 and December 31, 2013, the fair value for these financial instruments was not estimated. The carrying value of these investments was approximately $10.4 million at both September 30, 2014 and December 31, 2013, and is included in Other nonutility investments.

16. 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 a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west-central Ohio. The Electric Utility Services segment provides electric distribution services primarily 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.

The Nonutility Group has historically reported five segments: Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses. Results in the Coal Mining segment include the results of Vectren Fuels through August 29, 2014 when it exited the coal mining business through the sale of Vectren Fuels (see Note 9 for more details of this transaction).

Additionally, ProLiance exited the energy marketing business in 2013. In its 2014 periodic reports, the Company reports the Energy Marketing segment information for 2013, which is inclusive of the Company's share of the loss from operations and its share of the loss on sale as recorded by ProLiance Energy.

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)	2014	2013	2014	2013
Revenues				
Utility Group				
Gas Utility Services	$105.1	$101.9	$681.1	$555.8
Electric Utility Services	165.9	165.8	480.9	470.0
Other Operations	9.6	9.5	28.7	28.5
Eliminations	(9.5)	(9.5)	(28.5)	(28.3)
Total Utility Group	271.1	267.7	1,162.2	1,026.0
Nonutility Group				
Infrastructure Services	245.6	234.3	546.6	580.5
Energy Services	42.3	19.4	92.5	63.8
Coal Mining	67.2	83.3	234.3	218.5
Total Nonutility Group	355.1	337.0	873.4	862.8
Corporate & Other Group	0.3	0.3	0.8	0.3
Eliminations	(30.9)	(25.4)	(101.5)	(77.9)
Consolidated Revenues	$595.6	$579.6	$1,934.9	$1,811.2
Profitability Measure - Net Income (Loss)				
Utility Group Net Income (Loss)				
Gas Utility Services	$(5.1)	$(3.8)	$33.9	$37.2
Electric Utility Services	26.7	26.6	65.9	60.1
Other Operations	2.7	2.5	8.7	7.3
Utility Group Net Income	24.3	25.3	108.5	104.6
Nonutility Group Net Income (Loss)				
Infrastructure Services	23.5	20.4	27.6	35.2
Energy Services	0.1	0.2	(4.7)	(2.0)
Coal Mining	(2.1)	(2.3)	(21.4)	(12.0)
Energy Marketing	—	—	—	(37.5)
Other Businesses	0.1	(0.8)	(0.4)	(1.3)
Nonutility Group Net (Loss)	21.6	17.5	1.1	(17.6)
Corporate & Other Group Net (Loss)	1.4	—	0.8	(0.2)
Consolidated Net Income	$47.3	$42.8	$110.4	$86.8

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), Southern Indiana Gas and Electric Company (SIGECO), 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 574,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 143,000 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 313,000 natural gas customers located near Dayton in west-central Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business area. Results in the financial statements include the results of Vectren Fuels, Inc. (Vectren Fuels) through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. Further, prior to June 18, 2013, the Company had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). 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 (ProLiance Energy). Other minor operating results of the remaining ProLiance investment are reflected in Other Businesses. Enterprises 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.

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 2013 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, 2014 were earnings of $47.3 million, or $0.57 per share, compared to earnings of $42.8 million, or $0.52 per share for the three months ended September 30, 2013. For the nine months ended

September 30, 2014, consolidated net income was $110.4 million, or $1.34 per share, compared to $86.8 million or $1.05 per share for the nine months ended September 30, 2013.

In 2014, excluding the estimated loss on the disposition and year to date results attributable to the Company's Coal Mining segment, consolidated net income for the three and nine months ended September 30, 2014 was $49.4 million, or $0.60 per share and $131.8 million, or $1.60 per share, respectively.

In 2013, excluding the impact of the loss on disposition and operating losses attributable to the Company's investment in ProLiance, consolidated net income for the nine months ended September 30, 2013 was $124.3 million, or $1.51 per share. The 2013 results exclude the results of ProLiance prior to its sale of certain of the net assets of ProLiance Energy.

Losses Related to the Exit of the Coal Mining Business

On July 1, 2014, the Company announced that it had reached an agreement to sell its wholly-owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Sunrise owns and operates coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. The cash received at closing was approximately $320 million, including $24 million as the change in working capital from December 31, 2013, through closing. The transaction is further subject to a final working capital settlement. At June 30, 2014, the Company recorded an estimated loss on transaction, including costs to sell, of approximately $32 million, or $20 million after tax. At September 30, 2014, the pre-tax loss of $32 million was reflected in the Condensed Consolidated Statement of Income as a $42 million charge to other operating expense, offset by $10 million in lower depreciation expense as depreciation ceased for the assets classified as held for sale at June 30, 2014. The proceeds received, net of transaction costs and estimated tax payments totaled $291 million and were used to retire $200 million in outstanding Vectren Capital bank term loans and pay down outstanding short-term debt.

Results from Coal Mining for the quarter and year to date periods, inclusive of the loss on sale, were losses of $2.1 million and $21.4 million, net of tax, respectively. For the prior year, results for Coal Mining were losses of $2.3 million and $12.0 million, for the quarter and year to date periods ended September 30, 2013, respectively. More detailed information about sale of Vectren Fuels is included in the Results of Operations of the Nonutility Group within Management's Discussion and Analysis, as well as Note 9 to the consolidated financial statements.

Consolidated Results Excluding the Results From Coal Mining and ProLiance in the Year of Disposition (See Page 31, regarding the Use of Non-GAAP Measures)

Net income and earnings per share, excluding results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, in total and by group, for the three and nine months ended months ended September 30, 2014 and 2013 follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2014	2013	2014	2013
Net income, excluding Coal Mining & ProLiance results*	$49.4	$42.8	$131.8	$124.3
Attributed to:				
Utility Group	24.3	25.3	108.5	104.6
Nonutility Group, excluding Coal Mining & ProLiance results*	23.7	17.5	22.5	19.9
Corporate & other	1.4	—	0.8	(0.2)

Basic EPS, excluding Coal Mining & ProLiance results*	$0.60	$0.52	$1.60	$1.51
Attributed to:				
Utility Group	0.30	0.31	1.32	1.27
Nonutility Group, excluding Coal Mining & ProLiance results*	0.29	0.21	0.27	0.24
Corporate & other	0.01	—	0.01	—

*Excludes Coal Mining Results in 2014 and ProLiance Results in 2013 - Years of Disposition

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Utility Group
In the third quarter of 2014, the Utility Group earnings were $24.3 million, compared to $25.3 million in 2013. For the year to date period ended September 30, 2014, the Utility Group earned $108.5 million, compared to $104.6 million in 2013. The quarter over quarter decrease was primarily related to higher operating expenses. The year to date increase is driven by increased gas and electric margins offset by higher operating expenses driven by increased performance-based compensation expense as well as weather-related gas system maintenance resulting from the harsh winter.

Gas Utility Services
In the third quarter of 2014, Gas Utility Services reported a seasonal loss of $5.1 million compared to a loss of $3.8 million in the third quarter of 2013. In the nine months ended September 30, 2014, Gas Utility Services earnings were $33.9 million, compared to earnings of $37.2 million in 2013. Though customer margin increased in both quarter and year to date periods in 2014 from the returns from the Ohio infrastructure replacement programs and from small customer growth in the year to date period, the increase in margin was offset by higher operating expenses driven by weather-related maintenance of the gas system in the year to date period and by increased performance-based compensation expense in both quarter and year to date periods.

Electric Utility Services
In the third quarter of 2014, Electric Utility Services' earnings were $26.7 million, compared to $26.6 million in the third quarter of 2013. Electric Utility Services earned $65.9 million year to date in 2014, compared to earnings of $60.1 million for the nine months ended September 30, 2013. The increase in the year to date period is driven by the impact of weather on retail electric margin, which management estimates the after tax impact to be approximately $1.6 million favorable year to date compared to the 2013 period, as well as wholesale margin, which has a favorable after tax impact of $1.2 million. The increase in the quarter and year to date periods is also driven by the Company's lost revenue recovery mechanism which had an after tax favorable impact of $0.5 million and $1.9 million, respectively, related to electric conservation programs. Additionally, increases in both the quarter and year to date periods reflect increased deferral of interest on construction projects, offset by higher operating expenses due to increased performance-based compensation expense.

Nonutility Group
The Nonutility group results for the third quarter of 2014 were earnings of $23.7 million, excluding Coal Mining Results, compared to earnings of $17.5 million in the prior year. For the nine months ended September 30, 2014, the Nonutility Group reported earnings of $22.5 million, excluding Coal Mining results, compared to income of $19.9 million in 2013, excluding ProLiance results. ProLiance and Coal Mining results were excluded in the respective years of disposition. The earnings in the third quarter in 2014 reflect increased results from Infrastructure Services. Results were lower for the year to date period, due to the inability of work crews to complete their work as planned because of the adverse winter weather and related road restrictions during the first quarter in 2014. Year to date and quarterly results are further offset by reduced Energy Services' results that were higher in 2013 from tax deductions associated with energy efficiency projects.

Dividends

Dividends declared for the three months ended September 30, 2014, were $0.360 per share, compared to $0.355 per share for the same period in 2013. Dividends declared for the nine months ended September 30, 2014, were $1.080 per share compared to $1.065 per share for the same period in 2013.

Use of Non-GAAP Performance Measures and Per Share Measures

Results Excluding Coal Mining and ProLiance

This discussion and analysis contains non-GAAP financial measures that exclude the results related to Coal Mining and ProLiance in the year of disposition.

Management uses consolidated net income, consolidated earnings per share, and Nonutility Group net income, excluding results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, to evaluate its results. Coal Mining and ProLiance results that are excluded from the GAAP measures are inclusive of holding company costs (corporate allocations, interest and taxes) incurred to date. Management believes analyzing underlying and ongoing business trends is aided by the removal of Coal Mining and ProLiance results in the respective year of disposition and the rationale for using such non-GAAP measures is that, through the disposition of the Coal Mining segment and through the disposition by ProLiance Holdings of certain ProLiance Energy assets, the Company has now exited the gas marketing business and coal mining business.

A material limitation associated with the use of these measures is that the measures that exclude Coal Mining and 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 Coal Mining results in 2014 and ProLiance results in 2013, the years of disposition, 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 the Company’s consolidated results divided by the Company’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 the Company’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 Coal Mining results in 2014 and ProLiance results in 2013, the years of disposition.

	Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
(In millions, except EPS)	GAAP Measure	Exclude Coal Mining Results	Non-GAAP Measure	GAAP Measure	Exclude Coal Mining Results	Non-GAAP Measure
Consolidated						
Net Income	$47.3	$2.1	$49.4	$110.4	$21.4	$131.8
Basic EPS	$0.57	$0.03	$0.60	$1.34	$0.26	$1.60
Nonutility Group Net Income	$21.6	$2.1	$23.7	$1.1	$21.4	$22.5

	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

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, 2014 and 2013, follow:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2014	2013	2014	2013
OPERATING REVENUES				
Gas utility	$105.1	$101.9	$681.1	$555.8
Electric utility	165.9	165.8	480.9	470.0
Other	0.1	—	0.2	0.2
Total operating revenues	271.1	267.7	1,162.2	1,026.0
OPERATING EXPENSES				
Cost of gas sold	28.8	27.5	343.4	235.4
Cost of fuel & purchased power	50.3	50.4	155.4	154.5
Other operating	79.9	74.0	259.7	236.9
Depreciation & amortization	51.0	49.7	151.5	146.8
Taxes other than income taxes	11.7	11.6	44.3	41.3
Total operating expenses	221.7	213.2	954.3	814.9
OPERATING INCOME	49.4	54.5	207.9	211.1
OTHER INCOME - NET	4.8	2.0	12.4	6.8
INTEREST EXPENSE	16.6	15.6	50.0	49.2
INCOME BEFORE INCOME TAXES	37.6	40.9	170.3	168.7
INCOME TAXES	13.3	15.6	61.8	64.1
NET INCOME	$24.3	$25.3	$108.5	$104.6
CONTRIBUTION TO VECTREN BASIC EPS	$0.30	$0.31	$1.32	$1.27

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.

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)	2014	2013	2014	2013
Gas utility revenues	$105.1	$101.9	$681.1	$555.8
Cost of gas sold	28.8	27.5	343.4	235.4
Total gas utility margin	$76.3	$74.4	$337.7	$320.4
Margin attributed to:				
Residential & commercial customers	$57.6	$56.4	$248.3	$243.4
Industrial customers	11.8	12.1	42.7	41.9
Other	2.3	2.2	8.7	7.6
Regulatory expense recovery mechanisms	4.6	3.7	38.0	27.5
Total gas utility margin	$76.3	$74.4	$337.7	$320.4
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	6.7	6.5	84.3	73.6
Industrial customers	23.5	24.6	83.2	80.7
Total sold & transported volumes	30.2	31.1	167.5	154.3

Gas Utility margins were $76.3 million and $337.7 million for the three and nine months ended September 30, 2014, and compared to 2013, increased $1.9 million quarter over quarter and $17.3 million year to date. Year to date, customer margin increased $2.9 million compared to 2013 from small customer growth and large customer usage. Additionally, year to date margin was favorably impacted by $2.4 million from the return from infrastructure replacement programs, particularly in Ohio. With rate designs that substantially limit the impact of weather on margin, heating degree days that were 115 percent of normal in Ohio and 110 percent of normal in Indiana during the nine months ended September 30, 2014, compared to 103 percent of normal in Ohio and 100 percent of normal in Indiana during 2013, had a slight favorable impact on small customer margin. Weather was also the primary driver in the higher volumetric pass through margin, which increased $10.5 million year to date compared to the prior year.

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)	2014	2013	2014	2013
Electric utility revenues	$165.9	$165.8	$480.9	$470.0
Cost of fuel & purchased power	50.3	50.4	155.4	154.5
Total electric utility margin	$115.6	$115.4	$325.5	$315.5
Margin attributed to:				
Residential & commercial customers	$73.0	$73.8	$201.7	$195.0
Industrial customers	29.7	28.6	83.6	82.5
Other	0.9	1.4	2.9	3.1
Regulatory expense recovery mechanisms	2.7	2.2	9.3	6.7
Subtotal: retail	$106.3	$106.0	$297.5	$287.3
Wholesale power & transmission system margin	9.3	9.4	28.0	28.2
Total electric utility margin	$115.6	$115.4	$325.5	$315.5
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	759.0	769.6	2,136.5	2,072.1
Industrial customers	749.1	729.7	2,101.6	2,087.0

Other customers	5.3	4.9	16.2	15.5
Total retail volumes sold	1,513.4	1,504.2	4,254.3	4,174.6

Retail
Electric retail utility margins were $106.3 million and $297.5 million for the three and nine months ended months ended September 30, 2014, and compared to 2013, increased by $0.3 million in the quarter and $10.2 million year to date. Electric results, which are not protected by weather normalizing mechanisms, experienced a $0.9 million decrease in the third quarter 2014 in small customer margin related to weather as cooling degree days were 91 percent of normal compared to 99 percent of normal in 2013. For the year to date period, electric results were positively impacted by weather, resulting in a year to date increase of $2.7 million in small customer margin. Margin from regulatory expense recovery mechanisms increased $2.6 million year to date 2014 compared to 2013, driven primarily by a corresponding increase in operating expenses associated with the electric state-mandated conservation programs and MISO costs. As conservation initiatives continue, in the nine months ended September 30, 2014, the Company's lost revenue recovery mechanism contributed increased margin of $3.1 million related to electric conservation programs.

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)	2014	2013	2014	2013
MISO Transmission system sales	$8.1	$8.6	$20.8	$23.1
MISO Off-system sales	1.2	0.8	7.2	5.1
Total wholesale margin	$9.3	$9.4	$28.0	$28.2

Transmission system margin associated with qualifying projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $20.8 million and $23.1 million during the nine months ended September 30, 2014 and 2013, respectively. During the third quarter of 2014, transmission system margin was $8.1 million compared to $8.6 million for the same period in 2013. As of September 30, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $144.5 million at September 30, 2014. These projects include an interstate 345 Kv transmission line that connects the Company’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. Although the allowed return is currently being challenged as discussed below in Rate and Regulatory Matters, once placed into service, these projects earn a FERC approved equity rate of return of 12.38 percent on the net plant balance. Operating expenses are also recovered. The Company has established a reserve pending the outcome of this complaint. The 345 Kv project is the largest of these qualifying projects, with a cost of $106.8 million that earned 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, 2014, margin from off-system sales was $7.2 million, compared to $5.1 million in 2013. In the third quarter of 2014 margin from off system sales was $1.2 million compared to $0.8 million in 2013. 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.

Utility Group Operating Expenses

Other Operating
During the third quarter of 2014, other operating expenses were $79.9 million, an increase of $5.9 million. Excluding costs that are recovered directly in margin, the increase is primarily related to increased performance-based compensation. For the nine months ended September 30, 2014, other operating expenses were $259.7 million, an increase of $22.8 million, compared to 2013. Costs that are recovered directly in margin account for $9.9 million of the year to date increase. Excluding these pass through costs, other operating expenses increased $12.9 million year to date, compared to the same period in 2013, primarily associated with increased energy delivery expenses of $3.8 million due to the harsh winter weather in the first quarter 2014 and an increase in performance-based compensation expense of $5.2 million.

Depreciation & Amortization
In the third quarter of 2014, depreciation and amortization expense was $51.0 million, compared to $49.7 million in 2013. For the nine months ended September 30, 2014, depreciation and amortization expense was $151.5 million, which represents an increase of $4.7 million compared to 2013. Both year to date and quarter periods reflect increased plant placed into service.

Taxes Other Than Income Taxes
Taxes other than income taxes were $11.7 million for the third quarter of 2014, an increase of $0.1 million, compared to 2013. Year to date, taxes other than income taxes were $44.3 million compared to $41.3 million for the year to date period in 2013. The increase of $3.0 million is primarily due to higher revenue taxes associated with increased consumption and higher gas costs. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with higher gas utility and electric utility revenues reflected in margin attributable to regulatory expense recovery mechanisms.

Other Income - Net

Other income-net reflects income of $4.8 million for the third quarter of 2014, an increase of $2.8 million, compared to 2013. Year to date, other income-net reflects income of $12.4 million compared to $6.8 million, compared to 2013. Year to date results include increased AFUDC of approximately $5.5 million driven primarily by higher capital spending.

Rate & Regulatory Matters

Regulatory Treatment of Investments in Natural Gas Infrastructure Replacement
The Company monitors and maintains its natural gas distribution system to ensure that natural gas is delivered in a safe and efficient manner. The Company's natural gas utilities are currently engaged in replacement programs in both Indiana and Ohio to mitigate risk, improve the system, and comply with applicable regulations. Laws in both Indiana and Ohio were passed that provide utilities the opportunity to timely recover costs of federally mandated projects and other infrastructure improvement projects outside of a base rate proceeding.

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 included in the DRR. The Order also initially established a prospective bill impact evaluation on the annual deferrals. To date, the Company has made capital investments under this rider totaling $132.9 million. Regulatory assets associated with post in service carrying costs and depreciation deferrals were $12.1 million and $9.3 million at September 30, 2014 and December 31, 2013, respectively. Due to the expiration of the initial five year term for the DRR in early 2014, the Company filed a request in August 2013 to extend and expand the DRR. On February 19, 2014, the PUCO approved a Stipulation entered into by the PUCO Staff and the Company which provided for the extension of the DRR for the recovery of costs incurred through 2017 and expanded the types of investment covered by the DRR to include recovery of other infrastructure investments. The Order also approved an adjustment to the bill impact evaluation, limiting the resulting DRR rate per month for residential and small general service customers to specific graduated levels over the next five years. The Company's five year capital expenditure plan related to these infrastructure investments for calendar years 2013 through 2017 totals approximately $200 million, subject to the DRR rate caps approved in the Order. In addition, the Order approved the Company's commitment that the DRR can only be further extended as part of a base rate case. On May 1, 2014, the Company filed its annual request to adjust the DRR for recovery of costs incurred through December 31, 2013. On August 27, 2014 the PUCO issued an Order approving the Company’s revised DRR rate, effective September 1, 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 deferral application under this law, reflecting its 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 small general service customer per month. In addition, the Order approved the Company's proposal that subsequent requests for accounting authority will be filed annually in April. The Company submitted its most recent annual filing on April 30, 2014, which covers the Company’s capital expenditure program through calendar year 2014.

Given the extension of the DRR through 2017 as discussed above and the continued ability to defer other capital expenses under House Bill 95, it is anticipated that the Company will file a general rate case for the inclusion in rate base of the above costs near the expiration of the DRR. As such, the bill impact limits discussed above are not expected to be reached given the Company's capital expenditure plan during the remaining four year time frame.

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 Indiana Gas and $3 million annually at SIGECO. The debt-related post in service carrying costs are recognized in the Condensed Consolidated Statements of Income currently. The recording of post in service carrying costs and depreciation deferral is limited by individual qualifying project to three years after being placed into service at SIGECO and four years after being placed into service at Indiana Gas. At September 30, 2014 and December 31, 2013, the Company has regulatory assets totaling $15.3 million and $12.1 million, respectively, associated with the deferral of depreciation and debt-related post in service carrying cost activities.

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 current 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 and recovered in the Company's next general rate case, which must be filed before the expiration of the seven year plan. 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.

While 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 Indiana Regulatory Mechanisms
The Company filed in November 2013 for authority to recover costs related to its gas infrastructure replacement and improvement programs in Indiana, including costs associated with existing pipeline safety regulations, using the mechanisms allowed under Senate Bill 251 and Senate Bill 560. On August 27, 2014, the Commission issued an Order approving the Company’s seven year capital infrastructure replacement and improvement plan, beginning in 2014, and the proposed accounting authority and recovery, pursuant to the legislation. As provided in the two laws, the Order approved semi-annual filings for rate recovery of 100 percent of the costs, inclusive of return, related to these capital investments and operating expenses associated with pipeline safety rules, with 80 percent of the costs recovered currently via an approved tracking mechanism and 20 percent of the costs deferred and recovered in the Company’s next base rate proceeding. In addition, the Order established guidelines for the Company to update its seven year capital investment plan annually, with detailed estimates provided for the upcoming calendar year. Finally, the Order approved the Company’s proposal to recover eligible costs via a fixed monthly rate per residential customer. On September 26, 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed a Notice of Appeal with the Indiana Court of Appeals in response to the IURC's Order. The specific issues raised by the OUCC have not yet been identified. An appeal was filed in response to the IURC's Order in Northern Indiana Public Service Company's (NIPSCO) Senate Bill 560 electric infrastructure proceeding, pertaining to certain issues regarding the Commission's authority to approve NIPSCO's infrastructure plan. The outcome of the NIPSCO appeal and its implications to the Company’s Order, if any, cannot be determined.

On October 1, 2014, the Company filed its initial request for approval of the revenue requirement associated with capital investment through June 30, 2014 as part of its approved infrastructure improvement plan. As the next step of the recovery process as outlined in the legislation, this filing, once approved, will initiate the rates necessary to begin cash recovery of 80 percent of the revenue requirement, with the remaining 20 percent deferred for recovery in the Company's next rate cases. Also in this filing, consistent with the guidelines set forth in the Order, the Company submitted an update to its seven year plan, to reflect changes to project prioritization as a result of both additional risk modeling and cost increases. The updated plan reflects capital expenditures of approximately $900 million, inclusive of an estimated $30 million of economic development related expenditures, over the seven year period beginning in 2014. The plan also includes approximately $15 million of annual operating costs associated with pipeline safety rules. Pursuant to Senate Bill 560, the Company expects an order by the end of 2014.

Indiana Gas GCA Cost Recovery Issue
On July 1, 2014, Indiana Gas filed its recurring quarterly Gas Cost Adjustment (GCA) mechanism, which included recovery of gas cost variances incurred for the period January through March 2014. In August 2014, the Indiana Office of Utility Consumer Counselor (OUCC) filed testimony opposing the recovery of approximately $3.9 million of natural gas commodity purchases incurred during this period on the basis that a gas cost incentive calculation had not been properly performed. The calculation at issue is performed by the Company's supply administrator. In the winter period at issue, a pipeline force majeure event caused the gas to be priced at a location that was impacted by the extreme winter temperatures. After further review, the OUCC has modified its position in testimony filed on November 5, 2014, and now supports a reduced disallowance of $3.0 million. The Company believes that the costs are

either recoverable in its GCA, or that if the incentive mechanism calculation is found to create a cost disallowance, any such loss would be allocated to its supply administrator. An order is expected in November 2014.

SIGECO Electric Environmental Compliance Filing

On January 17, 2014, SIGECO filed a request with the IURC for approval of capital investments estimated to be between $70 and $90 million on its coal-fired generation units to comply with new EPA mandates related to mercury and air toxin standards effective in 2015 and to address an outstanding Notice of Violation (NOV) from the EPA. Roughly half of the investment will be made to control mercury in both air and water emissions. The remaining investment will be made to address the NOV on alleged increases in sulfur trioxide emissions. Although the Company believes these investments are recoverable as clean coal technology under Senate Bill 29 and federal mandated investments under Senate Bill 251, the Company has requested deferred accounting treatment in lieu of timely recovery to avoid immediate customer bill impacts. The accounting treatment request seeks deferral of depreciation and property tax expense related to these investments, accrual of post in service carrying costs, and deferral of incremental operating expenses related to compliance with these standards. The Company filed its case-in-chief on March 14, 2014. Intervening parties filed their testimony on May 28, 2014, to which the Company responded with rebuttal testimony on June 20, 2014. A hearing was held beginning on July 30, 2014. The case has been fully briefed as of October 2, 2014, and the Company is awaiting a Commission order.

Coal Procurement Procedures

SIGECO annually submits its coal procurement plan for IURC review in a sub docket proceeding. Entering 2014, SIGECO had in place staggered term coal contracts with Vectren Fuels and one other supplier to provide supply for its generating units. During 2014, SIGECO entered into separate negotiations with Vectren Fuels and Sunrise Coal to modify its existing contracts as well as enter into new long-term contracts in order to secure supply of coal with specifications that support its compliance with the Mercury and Air Toxins Rule. Subsequent to the sale of Vectren Fuels to an affiliate of Sunrise Coal, all such contracts have been assigned to Sunrise Coal. Those contracts were submitted to the IURC for review as part of the 2014 annual sub docket proceeding. The OUCC filed testimony in September 2014 in support of the reasonableness of these contracts. A hearing was held in October 2014 and the Company is awaiting an order from the Commission.

On December 5, 2011 within the quarterly FAC filing, SIGECO submitted a joint proposal with the OUCC to reduce its fuel costs billed to customers by accelerating into 2012 the impact of lower cost coal under new term contracts effective after 2012. The cost difference was deferred to a regulatory asset and is being recovered over a six year period without interest beginning in 2014. The IURC approved this proposal on January 25, 2012, with the reduction to customer's rates effective February 1, 2012. The total balance deferred for recovery through the Company's FAC, starting February 2014, was $42.4 million, of which $37.1 million remains as of September 30, 2014.

SIGECO Electric Demand Side Management Program Filing

On August 16, 2010, SIGECO filed a petition with the IURC, seeking approval of its proposed electric Demand Side Management (DSM) Programs, recovery of the costs associated with these programs, recovery of lost margins as a result of implementing these programs for large customers, and recovery of performance incentives linked with specific measurement criteria on all programs. The DSM Programs proposed were consistent with a December 9, 2009 Order issued by the IURC, which, among other actions, defined long-term conservation objectives and goals of DSM programs for all Indiana electric utilities under a consistent statewide approach. In order to meet these objectives, the IURC Order divided the DSM programs into Core and Core Plus programs. Core programs are joint programs required to be offered by all Indiana electric utilities to all customers, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an Order approving an initial three year DSM plan in the SIGECO electric service territory that complied with the IURC's energy saving targets. Consistent with the Company's proposal, the Order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $3 million in 2012 and $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. On June 20, 2012, the IURC issued an Order approving a small customer lost margin recovery mechanism, inclusive of all previous deferrals. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the Company's last base rate proceeding. For the nine months ended September 30, 2014 and September 30, 2013, the Company recognized Electric revenue of $6.6 million and $3.5 million, respectively, associated with this approved lost margin recovery mechanism.

On March 28, 2014, Senate Bill 340 was signed into law. This legislation ends electric DSM programs on December 31, 2014 that have been conducted to meet the energy savings requirements established in the Commission's December 2009 Order. The legislation also allows for industrial customers to opt out of participating in energy efficiency programs. As of July 1, 2014, approximately 71 percent of the Company’s eligible industrial load has opted out of participation in the applicable energy efficiency programs. Indiana's governor has requested that the Commission make new recommendations for energy efficiency programs to be proposed for 2015 and beyond, and has also asked the legislature to consider further legislation requiring some level of utility sponsored energy efficiency programs. The Company filed a request for Commission approval of a new portfolio of DSM programs on May 29, 2014 to be offered in 2015. On October 15, 2014, the Commission issued an Order approving a Settlement between the OUCC and the Company regarding the new portfolio of DSM programs effective January 2015.

Indiana Gas Pipeline Safety Investigation

On April 11, 2012, the IURC's pipeline safety division filed a complaint against Indiana Gas alleging several violations of safety regulations pertaining to damage that occurred at a residence in Indiana Gas'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 was reached between the IURC's pipeline safety division and Indiana Gas that allowed Indiana Gas to continue to use its risk based approach to inspecting excavations and to allow the Company to continue using a mix of highly trained and qualified contractors and employees to perform inspections. On January 15, 2014, the IURC issued a Final Order in the case approving the settlement agreement, without modification.

Indiana Gas & SIGECO Gas Decoupling Extension Filing

On August 18, 2011, the IURC issued an Order granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015. The Order provides that the companies must submit an extension proposal no later than March 1, 2015.

FERC Return on Equity Complaint

On November 12, 2013, certain parties representing a group of industrial customers filed a joint complaint with the FERC under Section 206 of the Federal Power Act against MISO and various MISO transmission owners, including SIGECO. The joint parties seek to reduce the 12.38 percent return on equity used in the MISO transmission owners’ rates, including SIGECO’s formula transmission rates, to 9.15 percent, and to set a capital structure in which the equity component does not exceed 50 percent. The MISO transmission owners filed their response to the complaint on January 6, 2014, opposing any change to the return. As of September 30, 2014, the Company had invested approximately $157.7 million in qualifying projects. The net plant balance for these projects totaled $144.5 million at September 30, 2014.

This joint complaint is similar to a complaint against the New England Transmission Owners (NETO) filed in September 2011, which requested that the 11.14 percent incentive return granted on qualifying investments in NETO be lowered. On October 16, 2014, the FERC issued an Order in the NETO case approving the 10.57 percent return on equity and the methodology set out in its June 19, 2014 decision.

In addition to the NETO ruling, the FERC acknowledged that the pending complaint raised against the MISO transmission owners is reasonable, and ordered the initiation of a formal settlement discussion, mediated by a FERC appointed judge, in November 2014. If a settlement is not reached, the case will move to a formal evidentiary hearing before the FERC. The Company has established a reserve pending the outcome of this complaint.

Legislative & Environmental Matters

Indiana Senate Bill 1

In March 2014, Indiana Senate Bill 1 was signed into law. This legislation phases in a 1.6 percent rate reduction to the Indiana Adjusted Gross Income Tax Rate for corporations over a six year period. Pursuant to this legislation, the tax rate will be lowered by 0.25 percent each year for the first five years and 0.35 percent in year six beginning on July 1, 2016 to the final rate of 4.9 percent effective July 1, 2021. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the first quarter of 2014, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251
Indiana Senate Bill 251 is also applicable to federal environmental mandates impacting Vectren South's electric operations. The Company continues with its ongoing evaluation of 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 SO2 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 SO2 and NOX allowances, CSAPR reduced the ability of facilities to meet emission reduction targets through allowance trading. CSAPR reductions were to be achieved with initial step reductions beginning January 1, 2012, and final compliance to be achieved in 2014. On December 30, 2011, a reviewing 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 April 2014, the US Supreme Court upheld CSAPR. On June 26, 2014, the EPA asked the federal appeals court to lift the stay of the rule. EPA also asked the court to approve a new deadline schedule for entities that must comply, with the first phase caps starting in 2015 and 2016, and the second phase in 2017. On October 23, 2014 the Court granted the EPA’s request to lift the CSAPR stay, but did not finalize the new implementation dates. While it is possible that the EPA could further revise the rule prior to implementation, the Company does not anticipate a significant impact from the Supreme Court's decision based upon the investments it has already made in pollution control technology to meet the requirements of CAIR. The Company remains in full compliance with CAIR (see additional information below "Conclusions Regarding Air and Water 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). Multiple judicial challenges were filed, and the EPA agreed to reconsider MATS requirements for new construction, as the 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. In April 2014, the U.S. Court of Appeals for the D.C. Circuit rejected various challenges to the rule for existing sources that were brought by industry and state petitioners. In July a coalition of twenty-one states, including Indiana, filed a petition for certiorari with the U.S. Supreme Court seeking review of the decision of the appellate court. The Company continues to proceed with its MATS compliance strategy. This plan is currently before the IURC for approval, and the Company anticipates full compliance by the applicable deadlines.

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 Selective Catalytic Reduction (SCR) systems, the correct permits were not obtained or the best available control technology to control incidental sulfuric acid mist was not installed. The Company reached a settlement in principle with the EPA to resolve the NOV. That settlement was contemplated in the plan filed with the IURC in the SIGECO Electric Environmental Compliance Filing.

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" (BTA) 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 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 was issued on May 19, 2014. The final rule does not mandate cooling water tower retrofits but requires a case by case assessment of BTA for each facility. The final rule lists seven presumptive technologies which would qualify as BTA. These technologies range from intake screen modifications to cooling water tower retrofits. Ecological and technology assessment studies must be completed prior to determining BTA for the Company's facilities. The Company believes that capital investments will likely be in the range of $4 million to $8 million. Costs for compliance with these final regulations should qualify as federally mandated regulatory requirements and be recoverable under Indiana Senate Bill 251 referenced above.

Under the Clean Water Act, the EPA sets technology-based guidelines for water discharges from new and existing facilities. The 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. The 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 Air and Water 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 SCR systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with AGC. 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 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. Some operational modifications to the control equipment are likely. 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 $70 million and $90 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. On January 17, 2014, the Company filed its request with the IURC seeking approval to upgrade its existing emissions control equipment to comply with the MATS Rule, take steps to address the EPA's allegations in the NOV and comply with new mercury limits to the waste water discharge permits at the Culley and Brown generating stations. In that filing, the Company has proposed to defer recovery of the costs until 2020 in order to mitigate the impact on customer rates in the near term. In July a hearing was held before the IURC in this matter. The case has been fully briefed as of October 2, 2014, and the Company is awaiting a Commission order.

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. Recently the EPA entered into a consent decree in which it agreed to finalize by December 2014 its determination whether to regulate ash as hazardous waste, or the less stringent solid waste designation.

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 only 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 cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. The endangerment finding was finalized in December 2009, concluding that carbon emissions pose an endangerment to public health and the environment.

The EPA has finalized two sets of 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, and in June 2014 the US Supreme Court upheld the regulations with respect to applicability to major sources such as coal-fired power plants that are required to hold PSD construction and Title V air operating permits for other criteria pollutants.

While the Company has no plans to invest in new coal fired generation, there is also a rule making and related legal challenge involving new source performance standards for new construction. This rulemaking must be finalized and withstand legal scrutiny in order for the EPA to implement its proposed new source performance standards for existing units discussed below.

In July 2013, the President announced a Climate Action Plan, which calls on the EPA to finalize the rule for new construction expeditiously, and by June 2014 propose, and by June 2015 finalize, New Source Performance Standards (NSPS) for GHG's for existing electric generating units which would apply to the Company's power plants. States must have their implementation plans to the EPA no later than June 2016. On June 2, 2014, the EPA proposed its rule for states to regulate CO_2 emissions from existing electric generating units. The rule, when final, will require states to adopt plans that reduce CO_2 emissions by 30 percent from 2005 levels by 2030. Unlike most rulemakings which allow for a 30 day public comment period, the EPA provided an initial 120 days from publication of the proposal in the Federal Register, and a subsequent extension of the public comment period was granted to December 1, 2014. The proposal sets state-specific CO_2 emission rate-based CO_2 goals (measured in lb CO_2/MWh or “megawatt hour”) and guidelines for the development, submission and implementation of state plans to achieve the state goals. These state-specific goals are calculated based upon 2012 average emission rates aggregated for all fossil fuel-based units in the state. For Indiana, the proposal uses a 2012 emission rate of 1,923 lb CO_2/MWh, and sets an interim goal of 1,607 lb CO_2/MWh and a final emission goal of 1,531 lb CO_2/MWh that must be met by 2030. Under this proposal, these CO_2 emission rate goals do not apply directly to individual units, or generating systems. They are state goals. As such, the state must establish a framework that will guide how compliance will be met on a statewide basis. The state’s interim or “phase in” goal of 1,607 lb CO2/MWh must be met as averaged over a ten year period (2020 - 2029) with progress toward this goal to be demonstrated for every two rolling calendar years starting in 2020, with the first report due in 2022.

Under the proposal all states have unique goals based upon each state’s mix of electric generating assets. The EPA is proposing a 20 percent reduction in Indiana’s total CO2 emission rate compared to 2012. At 20 percent Indiana’s CO2 emission rate reduction requirement is tied with West Virginia as the 9th lowest reduction requirement in US. This is due in part to the EPA’s attempt to recognize the existing generating resource mix in the state and take into account each state’s ability to cost effectively lower its CO2 emission rate through a portfolio approach including energy efficiency and renewables, improving power plant heat rates, and dispatching lower emitting fuel sources. Each state’s goals were set by taking 2012 emissions data and applying four “building blocks” of emission rate improvements that the EPA asserts can be achieved by that state. These four building blocks constitute the EPA’s determination of “Best System of Emission Reductions that has been adequately demonstrated,” which defines the EPA’s authority under § 111(d) for existing sources. When applied to each state, the portfolio approach leads to significant differences in requirements across state lines. With the exception of building block number 1 (heat rate improvement of 6 percent), other building blocks are tailored to individual states based upon each state’s existing generating mix and what the EPA concluded a state could reasonably accomplish to reduce its CO2 emission rate. Despite having just been recently proposed and not expected to be finalized until June of 2015, legal challenges to the EPA's proposal have begun. On July 31, 2014, litigation was filed by the state of Indiana and other parties challenging the rules which may delay the timing of approval of the various state plans.

With respect to the state of Indiana, the four building blocks that support Indiana’s goal are as follows:

(1) Heat rate (HR) improvements of 6 percent (this is consistently applied to all states).
(2) Increasing the dispatch of existing natural gas baseload generation sources to 70 percent.
(3) Renewable energy portfolio requirements of 5 percent (interim) and 7 percent (final).
(4) Energy efficiency / DSM that results in reductions of 1.5 percent annually starting in 2020, ending at a sustained 11 percent by 2030.

Under the proposal, Indiana may choose to implement a program based upon an annual average emission rate target or convert that target rate to a comparable CO2 emission cap. Indiana is the 5th largest carbon emitter in the nation in tons of CO2 produced from electric generation. In 2013, Indiana’s electric utilities generated 105.6 million tons of CO2. The Company’s share of that total was 6.3 million, or <6 percent. Since 2005, the Company’s emissions of CO2 have declined 23 percent (on a tonnage basis). These reductions have come from the retirement of FB Culley Unit 1, expiration of municipal contracts, electric conservation and the addition of renewable generation and the installation of more efficient dense pack turbine technology. With respect to CO2 emission rate, since 2005 the Company has lowered its CO2 emission rate (as measured in lbs CO2/MWh) from 1967 lbs CO2/MWh to 1922 lbs CO2/MWh, for a reduction of 3 percent. the Company’s CO2 emission rate of 1922 lbs/MWh is basically the same as the State’s average CO2 emission rate of 1923 lb CO2/MWh.

Impact of Legislative Actions & Other Initiatives is Unknown
If the regulations referenced above are finalized by the EPA, or if legislation requiring reductions in CO2 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 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 were based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. As the EPA moves toward finalization of the NSPS for existing sources and the State of Indiana begins formulation of its state implementation plan, the Company will have more information to enable it to better assess potential compliance costs with a final regulation. Costs to purchase allowances that cap GHG emissions or expenditures made to control emissions or lower carbon emission rates 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 as referenced above or Senate Bill 29, which was used by the Company to recover its initial pollution control investments.

Renewables
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 4 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 $43.4 million ($23.2 million at Indiana Gas and $20.2 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 $14.3 million of the expected $15.8 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, 2014 and December 31, 2013, approximately $4.3 million and $5.7 million, respectively, of accrued, but not yet spent, costs are included in Other Liabilities related to the Indiana Gas and SIGECO sites.

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Results of Operations of the Nonutility Group

The Nonutility Group operates in two primary business areas: Infrastructure Services and Energy Services. Infrastructure Services provides underground pipeline construction and repair services. Energy Services provides energy performance contracting and sustainable infrastructure, such as renewables, distributed generation, and combined heat and power projects. Prior to August 29, 2014, the Company had activities in its Coal Mining business area. Results in the financial statements include the results of Vectren Fuels, Inc. (Vectren Fuels) through the date of sale of August 29, 2014, when the Company exited the coal mining business through the sale of Vectren Fuels. Further, prior to June 18, 2013, the Company had activities in its Energy Marketing business area. Energy Marketing marketed and supplied natural gas and provided energy management services through ProLiance Holdings, LLC (ProLiance or ProLiance Holdings). 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 (ProLiance Energy). Other minor operating results of the remaining ProLiance investment are reflected in Other Businesses. Enterprises 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.

The Nonutility Group results were earnings of $21.6 million and $1.1 million for the three and nine months ended September 30, 2014, respectively compared to earnings of $17.5 million and a net loss of $17.6 million for the three and nine months ended September 30, 2013, respectively. Nonutility Group earnings, excluding the results from Coal Mining in 2014 and ProLiance in 2013, the years of disposition, for the three and nine months ended months ended September 30, 2014 and 2013 follow. See page 32 for a reconciliation of Non-GAAP performance measures.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share amounts)	2014	2013	2014	2013
NET INCOME EXCLUDING COAL MINING & PROLIANCE RESULTS*	$23.7	$17.5	$22.5	$19.9
CONTRIBUTION TO VECTREN BASIC EPS, EXCLUDING COAL MINING & PROLIANCE RESULTS*	$0.29	$0.21	$0.27	$0.24
NET INCOME (LOSS) ATTRIBUTED TO:				
Infrastructure Services	$23.5	$20.4	$27.6	$35.2
Energy Services	0.1	0.2	(4.7)	(2.0)
Coal Mining*		(2.3)		(12.0)
Other Businesses	0.1	(0.8)	(0.4)	(1.3)

*Excludes Coal Mining Results in 2014 and ProLiance Results in 2013 - Years of Disposition

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, results for Infrastructure Services' operations for the third quarter of 2014 were earnings of $23.5 million, compared to earnings of $20.4 million for the same period in the prior year. During the nine months ended September 30, 2014, earnings were $27.6 million, compared to $35.2 million year to date in 2013.

Results were lower for the year to date period, due to the inability of work crews to complete their work as planned because of the adverse winter weather and related road restrictions in the first two quarters. Recovery of the slow start to the year began in the latter part of the second quarter and continued in the third quarter as evidenced by the increased results. Further, results for the prior year to date period reflect the favorable impacts of an 80-mile pipeline project. With a significant backlog of $625 million at September 30, 2014, compared to $535 million at December 31, 2013, the Company expects that much of the delayed work will be completed over the remainder of the year, along with other planned work, assuming normal weather. Revenues for the year to date period were $546.6 million, compared to revenues of $580.5 million for the same period in 2013.

The backlog amounts above include estimates of revenues to be realized under blanket contracts. Projects included in backlog can be subject to delays or cancellation as a result of regulatory requirements, adverse weather conditions, and customer requirements, among other factors, which could cause actual revenue amounts to differ significantly from the estimates and/or revenues to be realized in periods other than originally expected.

Construction activity, generally, is expected to remain strong as aging natural gas and oil pipelines and related infrastructure are repaired and replaced. In addition, construction activity is expected to be favorably impacted as pipeline operators construct new pipelines due to the continued strong demand for new shale gas and oil infrastructure.

Energy Services

Energy Services provides energy performance contracting and sustainable infrastructure, such as distributed generation and combined heat and power projects through its wholly-owned subsidiary Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services results were roughly flat in the third quarter of 2014 compared to the third quarter of 2013. For the nine months ended September 30, 2014, Energy Services operated at a loss of $4.7 million, compared to a loss of $2.0 million in 2013. The decrease in earnings reflects the favorable impact in 2013 of federal income tax incentives that expired on December 31, 2013. Excluding the net income impact of the federal income tax deductions in 2013, results were losses of $2.2 million and $5.3 million in the three and nine month periods ended September 30, 2013, respectively.

Though some positive indications are being seen in sales opportunities, the results in the nine months ended September 30, 2014, also reflect increased operating expenses, including amortization of acquired intangibles associated with the April 1, 2014 acquisition of the federal business sector of Chevron Energy Solutions (CES). At September 30, 2014, performance contracting backlog was $120 million, compared to $72 million on December 31, 2013.

The Company's long-term view of the performance contracting and sustainable infrastructure opportunities remains positive as the national focus on energy conservation, renewable energy, and sustainability continues given the expected rise in power prices across the country. ESG believes it is well-positioned for this future growth. This national focus is further evidenced by the President's announcement on May 9, 2014 of an additional $2 billion, which doubles the goal, for federal energy efficiency performance contracting project spend through 2016. Expected activity in the federal sector, as well as positive indications in the public sector and sustainable infrastructure businesses, is reflected in a significant increase in the sales funnel. The outlook remains strong on the ability to convert those opportunities into contracts over time.

Coal Mining

Prior to August 29, 2014, Coal Mining owned, and through its contract miners, mined and sold coal to the Company's utility operations and to third parties through its wholly-owned subsidiary, Vectren Fuels. On July 1, 2014, the Company announced that it had reached an agreement to sell Vectren Fuels to Sunrise Coal, LLC (Sunrise), an Indiana-based wholly-owned subsidiary of Hallador Energy Company. Sunrise owns and operates coal mines in the Illinois Basin. On August 29, 2014, the transaction closed. The cash received at closing was approximately $320 million, including $24 million as the change in working capital from December 31, 2013, through closing. The transaction is further subject to a final working capital settlement. At June 30, 2014, the Company recorded an estimated loss on transaction, including costs to sell, of approximately $32 million, or $20 million after tax. At September 30, 2014, the pre-tax loss of $32 million was reflected in the Condensed Consolidated Statement of Income as a $42 million charge to other operating expense, offset by $10 million in lower depreciation expense as depreciation ceased for the assets classified as held for sale at June 30, 2014. The proceeds received, net of transaction costs and estimated tax payments totaled $291 million and were used to retire $200 million in outstanding Vectren Capital bank term loans and pay down outstanding short-term debt.

Results from Coal Mining for the quarter and year to date periods, inclusive of the loss on sale, were losses of $2.1 million and $21.4 million, net of tax, respectively. For the prior year, results for Coal Mining were losses of $2.3 million and $12.0 million, for the quarter and year to date periods ended September 30, 2013, respectively.

ProLiance

Disposition of ProLiance Energy
The Company has an investment in ProLiance Holdings, an affiliate of the Company and Citizens Energy Group (Citizens). On June 18, 2013, ProLiance Holdings 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, to a subsidiary of Energy Transfer Partners, ETC Marketing, Ltd (ETC). The Company's remaining investment in ProLiance relates primarily to an investment in LA Storage, LLC (LA Storage). 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, 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. During the nine months ended September 30, 2013, the Company’s share of ProLiance's results was a loss of $37.5 million.

LA Storage, LLC Storage Asset Investment
ProLiance Transportation and Storage, LLC (PT&S), a subsidiary of ProLiance, and Sempra Energy International (SEI), a subsidiary of Sempra Energy (SE), through a joint venture, have a 100 percent interest in a development project for salt-cavern natural gas storage facilities known as LA Storage. PT&S is the minority member with a 25 percent interest, which it accounts for using the equity method. The project is expected to include 17 Bcf of capacity, and has the potential for further expansion. This 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.

Approximately 12 Bcf of the storage, 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. The timing and extent of development of these caverns is dependent on market conditions, including pricing, need for storage capacity, and development of the liquefied natural gas market, among other factors. As of September 30, 2014 and December 31, 2013, ProLiance's investment in the joint venture was $35.6 million and $35.4 million, respectively.

The joint venture received a demand for arbitration from Williams Midstream Natural Gas Liquids, Inc. (“Williams”) in February 2011 related to a sublease agreement. Williams alleges that the joint venture was negligent in its attempt to convert certain salt caverns to natural gas storage and seeks damages of $56.7 million. The joint venture intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams. As such, as of September 30, 2014, 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

Revenue Recognition Guidance

In May 2014, the FASB issued new accounting guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for GAAP and IFRS. The amendments in this guidance state that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This new guidance requires improved disclosures to help users of financial statements better understand the nature, amount, timing, and uncertainty of revenue that is recognized. For a public entity, the guidance is effective for annual reporting periods beginning after December 15, 2016, with early adoption not permitted. An entity should apply the amendments in this update retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying this update recognized at the date of initial application. The Company is currently evaluating the standard to understand the overall impact it will have on the financial statements.

Investments in Qualified Affordable Housing Projects

In January 2014, the FASB issued new accounting guidance on accounting for investments in qualified affordable housing projects. The amendments in this guidance allows an entity to make an accounting policy election to account for investments in qualified affordable housing projects using a proportional amortization method, if certain conditions are met. Under the election, the entity would amortize the initial cost of the investment in proportion to the tax credits and other benefits received while recognizing the net investment performance in the income statement as a component of income tax expense (benefit). The guidance is effective for annual periods and interim reporting periods within those annual periods, beginning after December 15, 2014, with early adoption permitted. The Company is assessing if its affordable housing investments will qualify for the election and whether or not it will choose to exercise the election. Adoption of this guidance will not have a material impact on the Company's financial statements.

Financial Reporting of Discontinued Operations

In April 2014, the FASB issued new accounting guidance on reporting discontinued operations and disclosures of disposals of a company or entity. The guidance changes the criteria for reporting discontinued operations and provides for enhanced disclosures in this area. Under the new guidance, only disposals representing a strategic shift in operations should be presented as discontinued operations. Those strategic shifts should have a major effect on the organization's operations and financial results. Additionally, the new guidance requires expanded disclosures about discontinued operations to provide more information about the assets, liabilities, income, and expenses of discontinued operations. The new guidance also requires disclosure of the pre-tax income attributable to a disposal of a significant part of an organization that does not qualify for discontinued operations reporting. This guidance is effective for fiscal years beginning on or after December 15, 2014, with early adoption permitted. The Company did not adopt this guidance in accounting for the sale of its Coal Mining assets as discussed in footnote 9. The Company is currently evaluating the impact of this guidance, if any.

Accounting for Stock Compensation

In June 2014, the FASB issued new accounting guidance on accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the requisite service period. These amendments provide explicit guidance on whether to treat a performance target that could be achieved after the requisite service period as a performance condition that affects vesting or as a non-vesting condition that affects the grant-date fair value of an award. This guidance is effective for annual periods and interim periods within those periods beginning after December 15, 2015, with early adoption permitted. The Company’s current practice for accounting for stock compensation follows the prescribed manner as suggested by the update. Adoption of this guidance will not have a material impact on the Company’s financial statements.

Financial Reporting of Going Concern

In August 2014, the FASB issued new accounting guidance with respect to reporting on an entity's ability to continue as a going concern. This new guidance requires management to assess an entity's ability to continue as a going concern by incorporating and expanding upon certain principles that are currently in U.S. auditing standards, which requires disclosure surrounding what constitutes substantial doubt for the entity, including disclosure of management's plans to mitigate and alleviate substantial doubt. This guidance is effective for annual periods beginning after December 15, 2016 and for annual and interim periods thereafter, with early application permitted. Adoption of this guidance will not have a material impact on the Company’s financial statements.

Financial Condition

Within the Company’s consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and 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, 2014 approximated $320 million and $2 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 outstanding at September 30, 2014 approximated $875 million. As of September 30, 2014, Utility Holdings had $60 million in short-term borrowings outstanding. 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 new 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, 2014, was approximately $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.

Vectren Corporation's corporate credit rating is A-, as rated by Standard and Poor's Ratings Services (Standard and Poor's). Moody's Investor Services (Moody's) does not provide a rating for Vectren Corporation. The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at September 30, 2014, are A-/A2, as rated by Standard and Poor's and Moody’s, respectively. The credit ratings on SIGECO's secured debt are A/Aa3. Utility Holdings’ commercial paper has a credit rating of A-2/P-1. 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 50 percent and 46 percent of long-term capitalization at September 30, 2014 and December 31, 2013, 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, 2014, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A2 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 and incremental long-term debt. 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; 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 recently acquired an energy services business and may further expand its businesses through other 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.

On March 11, 2014, a $30 million Vectren Capital senior unsecured note matured. The Series A note, which was part of a private placement Note Purchase Agreement entered into on March 11, 2009, carried a fixed interest rate of 6.37 percent. The repayment of debt was funded from the Company's short-term credit facility.

On September 24, 2014, SIGECO issued two new series of tax-exempt debt totaling $63.6 million. Proceeds from the issuance were used to retire three series of tax-exempt bonds aggregating $63.6 million at a redemption price of par plus accrued interest. The principal terms of the two new series of tax-exempt debt are: (i) $22.3 million sold in a public offering and bear interest at 4 percent per annum, due September 1, 2044 and (ii) $41.3 million, due July 1, 2025, sold in a private placement at variable rates through September 2019.

On August 29, 2014, the Company closed on the sale of its wholly-owned coal mining subsidiary, Vectren Fuels, to Sunrise Coal, LLC. The initial cash proceeds from the sale of Vectren Fuels were used to retire $200 million in outstanding Vectren Capital bank term loans and pay down outstanding short-term debt.

Consolidated Short-Term Borrowing Arrangements

At September 30, 2014, 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 $290 million was available for the Utility Group operations and approximately $248 million was available for the wholly-owned Nonutility Group and corporate operations. Both Vectren Capital's and Utility Holdings' short-term credit facilities were amended on October 31, 2014 to extend their maturity until October 31, 2019. 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)	2014	2013	2014	2013
As of September 30				
Balance Outstanding	$60.1	$176.1	$2.3	$73.1
Weighted Average Interest Rate	0.31%	0.31%	1.28%	1.30%
Nine Months Ended September 30 Average				
Balance Outstanding	$15.3	$121.4	$46.1	$136.4
Weighted Average Interest Rate	0.28%	0.35%	1.29%	1.36%
Maximum Month End Balance Outstanding	$60.1	$176.1	$76.3	$173.8

	Utility Group Borrowings		Nonutility Group Borrowings	
(In millions)	2014	2013	2014	2013
Quarterly Average - September 30				
Balance Outstanding	$43.0	$153.8	$50.4	$104.2
Weighted Average Interest Rate	0.28%	0.34%	1.29%	1.33%
Maximum Month End Balance Outstanding	$60.1	$176.1	$76.3	$152.8

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 $4.7 million and $5.3 million in the nine months ended September 30, 2014 and 2013, respectively.

Potential Uses of Liquidity

Pension Funding Obligations

Currently, the Company anticipates making no contributions to its qualified pension plans in 2014.

Corporate Guarantees

The Company issues parent level guarantees to certain vendors and customers of its wholly-owned subsidiaries and unconsolidated affiliates. These guarantees do not represent incremental consolidated obligations; rather, they represent parental guarantees of subsidiary and unconsolidated affiliate obligations, in order to allow those subsidiaries and affiliates the flexibility to conduct business without posting other forms of collateral. At September 30, 2014, parent level guarantees, excluding guarantees of obligations of the federal business unit acquired from Chevron USA on April 1, 2014, as further described below, 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.

On April 1, 2014, Energy Systems Group acquired the federal sector energy services unit of Chevron Energy Solutions, from Chevron USA. Pursuant to the agreement, the acquisition includes a provision whereby Vectren Enterprises, Inc., the wholly-owned holding company for the Company's nonutility investments, provided CES with an indemnification for potential claims against the seller that could arise related to the performance of work undertaken by ESG.

The acquisition also includes ESG guarantees of performance under certain assumed contracts. The guarantees include energy savings that are used to satisfy project financing. The Company guarantees ESG's performance under these energy savings guarantees. The total maximum amount of the energy savings guarantees is approximately $140 million and will only be called upon in the event energy savings established under the existing contracts executed by CES are not achieved. Further, an energy facility operated by ESG and managed by Keenan Ft Detrick Energy, LLC (Keenan), is governed by an operations agreement. All payment obligations to Keenan under this agreement are also guaranteed by the Company. The Vectren Enterprises, Inc. provision providing indemnification to CES and the Company guarantee of the Keenan Ft Detrick Energy operations agreement with Keenan as discussed above, do not state a maximum guarantee. Due to the nature of work performed under these contracts, the Company cannot estimate a maximum potential amount of future payments.

In addition, the Company has approximately $15 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $9 million represent letters of credit supporting other nonutility operations.

While there can be no assurance that neither the Vectren Enterprises, Inc.'s indemnification nor the Company guarantee provisions will be called upon, the Company believes that the likelihood of a material amount being triggered under any of these provisions 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, 2014, there are 48 open surety bonds supporting future performance. The average face amount of these obligations is $6.0 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, 2014, approximately 46 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 accruals for these warranty and energy obligations as of September 30, 2014.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $110 million for the remainder of 2014. Nonutility capital expenditures and investments are estimated at $30 million for the remainder of 2014.

Contractual Obligations

The Company’s contractual obligations primarily consist of debt issued by Vectren Capital, certain plant and nonutility plant purchase commitments, and other long-term liabilities. For the nine months ended September 30, 2014, there were no significant changes to the Company’s contractual obligations from those identified in the Company’s Annual Report on Form 10-K for the year ended December 31, 2013, other than those which occur in the normal and ordinary course of business and those mentioned below.

As discussed above, on August 29, 2014 the sale of Vectren Fuels to Sunrise Coal, LLC was completed. The proceeds from the sale were used to retire $200 million in outstanding Vectren Capital bank term loans and to pay down other outstanding short-term debt. As a result, as of September 30, 2014, the Company’s long-term debt obligations were $1,577 million, and short-term debt obligations were $62 million.

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 $343.7 million and $388.9 million for the nine months ended September 30, 2014 and 2013, respectively. The decrease is driven primarily by changes in certain working capital accounts and tax payments related to the sale of Vectren Fuels.

Financing Cash Flow

Net cash flow required for financing activities was $321.1 million during the nine months ended September 30, 2014 compared to requirements of $119.8 million in 2013. The current year period reflects a decrease of net borrowings of $237 million due principally to the use of proceeds from the sale of Vectren Fuels as reflected in investing cash flow. The prior year period reflects significant refinancing activity to take advantage of the low interest rate environment. Financing activity in both periods presented reflect the payment of dividends.

Investing Cash Flow

Cash flow required for investing activities was $35.7 million and $279.3 million during the nine months ended September 30, 2014 and 2013, respectively. During the nine months ended September 30, 2014, approximately $320 million in proceeds were received from the sale of Vectren Fuels. Proceeds received comprised of $296 million in cash plus a $24 million change in working capital that is further subject to a working capital settlement. The use of cash for utility and nonutility capital expenditures has increased approximately $50 million compared to the nine months ended September 30, 2013. Investing activity presented in the nine months ended September 30, 2014, also reflects the acquisition of the federal business unit from Chevron Energy Solutions.

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 coal and natural gas 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 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, and remaining energy marketing 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 and benefit 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 energy services, including unanticipated cost increases in completion of the contracted work; changes in legislation and regulations impacting the industries in which the customers served operate; changes in economic influences impacting customers served; failure to properly estimate the cost to construct projects; the ability to attract and retain qualified employees; cancellation and/or reductions in the scope of projects by customers; credit worthiness of customers; and changing market conditions.
- 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 the purchase of the federal sector under Energy Services and the sale of Coal Mining and other 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.

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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 2013 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, 2014, 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, 2014, 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, 2014, 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 2013 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, 2014.

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	—	$—	—	—
August 1-31	624	$39.58	—	—
September 1-30	—	$—	—	—

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

3.1	Code of By-Laws of Vectren corporation as Most Recently Amended as of October 1, 2014 (filed and designated in Form 8-K, dated September 29, 2014, File No. 1-15467, as Exhibit 3.1)
4.1	SIGECO Supplemental Indenture dated as of September 1, 2014 (filed and designated in Form 8-K, dated September 25, 2014, File No. 1-15467, as Exhibit 4.1)
10.1	Amendment number two to Vectren Corporation Change in Control Agreement (specimen) (filed and designated in Form 8-K, dated September 29, 2014, File No. 1-15467, as Exhibit 10.1)
10.2	Credit Agreement, dated as of October 31, 2014, among Vectren Utility Holdings, Inc., as borrower (Vectren Utility); certain subsidiaries of Vectren Utility, as guarantors; Bank of America, N.A., as administrative agent, swing line lender and a letter of credit issuer; Wells Fargo Bank, National Association, JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein (filed and designated in Form 8-K, dated November 5, 2014, File No. 1-15467, as Exhibit 10.1)
10.3	Credit Agreement, dated as of October 31, 2014, among Vectren Capital, Corp., as borrower; Vectren Corporation, as guarantor; Wells Fargo Bank, National Association, as administrative agent, swing line lender and a letter of credit issuer; Bank of America, N.A., JPMorgan Chase Bank, N.A. and MUFG Union Bank, N.A., as co-syndication agents and letter of credit issuers; and the other lenders named therein (filed and designated in Form 8-K, dated November 5, 2014, File No. 1-15467, as Exhibit 10.2)
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 7, 2014	/s/M. Susan Hardwick M. Susan Hardwick Senior Vice President and Chief Financial Officer (Signing on behalf of the registrant and as Principal Accounting & Financial Officer)

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