VECTREN CORP
Form 10-Q
May 05, 2011

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2011

OR

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

For the transition period from ___________________ to ___________________

Commission file number: 1-15467

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

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

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

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

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

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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 x 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 x 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	81,717,844	April 30, 2011
Class	Number of Shares	Date

Access to Information

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

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

Definitions

BTU: British thermal units	MSHA: Mine Safety and Health Administration
FASB: Financial Accounting Standards Board	MW: megawatts
FERC: Federal Energy Regulatory Commission	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
IDEM: Indiana Department of Environmental Management	OUCC: Indiana Office of the Utility Consumer Counselor
IURC: Indiana Utility Regulatory Commission	PUCO: Public Utilities Commission of Ohio
BCF: billions of cubic feet	EPA: Environmental Protection Agency
MISO: Midwest Independent System Operator	Throughput: combined gas sales and gas transportation volumes

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	March 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash & cash equivalents	$34.5	$10.4
Accounts receivable - less reserves of $8.1 & $5.3, respectively	216.2	176.6
Accrued unbilled revenues	105.7	162.0
Inventories	132.4	187.1
Recoverable fuel & natural gas costs	3.0	7.9
Prepayments & other current assets	62.5	101.2
Total current assets	554.3	645.2
Utility Plant		
Original cost	4,827.4	4,791.7
Less: accumulated depreciation & amortization	1,867.6	1,836.3
Net utility plant	2,959.8	2,955.4
Investments in unconsolidated affiliates	126.5	135.2
Other utility & corporate investments	34.8	34.1
Other nonutility investments	41.0	40.9
Nonutility plant - net	527.6	488.3
Goodwill - net	262.3	242.0
Regulatory assets	183.1	189.4
Other assets	52.4	33.7
TOTAL ASSETS	$4,741.8	$4,764.2

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

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

	March 31, 2011	December 31, 2010
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$134.5	$183.7
Accounts payable to affiliated companies	28.5	59.6
Accrued liabilities	207.4	178.4
Short-term borrowings	122.3	118.3
Current maturities of long-term debt	103.4	250.7
Long-term debt subject to tender	30.0	30.0
Total current liabilities	626.1	820.7
Long-term Debt - Net of Current Maturities & Debt Subject to Tender	1,587.4	1,435.2
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	534.3	515.3
Regulatory liabilities	339.2	333.5
Deferred credits & other liabilities	198.6	220.6
Total deferred credits & other liabilities	1,072.1	1,069.4
Commitments & Contingencies (Notes 11-13)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 81.7 & 81.7 shares, respectively	685.5	683.4
Retained earnings	775.7	759.9
Accumulated other comprehensive income (loss)	(5.0)	(4.4)
Total common shareholders' equity	1,456.2	1,438.9
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$4,741.8	$4,764.2

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

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
OPERATING REVENUES		
Gas utility	$356.7	$468.1
Electric utility	146.4	144.9
Nonutility	179.5	127.3
Total operating revenues	682.6	740.3
OPERATING EXPENSES		
Cost of gas sold	195.1	297.8
Cost of fuel & purchased power	59.5	58.0
Cost of nonutility revenues	105.1	60.5
Other operating	141.6	128.9
Depreciation & amortization	59.1	55.8
Taxes other than income taxes	18.9	23.1
Total operating expenses	579.3	624.1
OPERATING INCOME	103.3	116.2
OTHER INCOME (EXPENSE)		
Equity in earnings (losses) of unconsolidated affiliates	(10.9)	8.2
Other income (loss) – net	2.4	(0.5)
Total other income (expense)	(8.5)	7.7
INTEREST EXPENSE	26.6	26.0
INCOME BEFORE INCOME TAXES	68.2	97.9
INCOME TAXES	23.6	34.7
NET INCOME	$44.6	$63.2
AVERAGE COMMON SHARES OUTSTANDING	81.7	81.0
DILUTED COMMON SHARES OUTSTANDING	81.7	81.2
EARNINGS PER SHARE OF COMMON STOCK:		
BASIC	$0.55	$0.78
DILUTED	$0.55	$0.78
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.345	$0.340

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

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$44.6	$63.2
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	59.1	55.8
Deferred income taxes & investment tax credits	18.5	9.5
Equity in (earnings) losses of unconsolidated affiliates	10.9	(8.2)
Provision for uncollectible accounts	5.9	6.5
Expense portion of pension & postretirement benefit cost	2.2	3.1
Other non-cash charges - net	3.2	8.4
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	31.5	12.9
Inventories	54.7	36.5
Recoverable/refundable fuel & natural gas costs	5.1	(9.4)
Prepayments & other current assets	39.0	42.7
Accounts payable, including to affiliated companies	(86.8)	(79.2)
Accrued liabilities	23.8	41.3
Unconsolidated affiliate dividends	-	6.9
Employer contributions to pension & postretirement plans	(29.2)	(4.3)
Changes in noncurrent assets	8.0	21.0
Changes in noncurrent liabilities	(2.1)	(4.0)
Net cash flows from operating activities	188.4	202.7
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Dividend reinvestment plan & other common stock issuances	1.7	1.5
Requirements for:		
Dividends on common stock	(28.2)	(27.5)
Retirement of long-term debt	(0.1)	(0.7)
Other financing activities	(1.4)	-
Net change in short-term borrowings	4.0	(49.2)
Net cash flows from financing activities	(24.0)	(75.9)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Unconsolidated affiliate distributions	-	0.5
Other collections	0.3	2.0
Requirements for:		
Capital expenditures, excluding AFUDC equity	(57.7)	(71.0)
Business acquisition, net of cash acquired	(82.9)	-
Other investments	-	(1.2)
Net cash flows from investing activities	(140.3)	(69.7)
Net change in cash & cash equivalents	24.1	57.1
Cash & cash equivalents at beginning of period	10.4	11.9

Cash & cash equivalents at end of period	$34.5	$69.0

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

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

1. Organization and Nature of Operations

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

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 111,000 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. The Ohio operations provide energy delivery services to over 314,000 natural gas customers located near Dayton in west central Ohio. The Ohio operations are owned as a tenancy in common by Vectren Energy Delivery of Ohio, Inc. (VEDO), a wholly owned subsidiary of Utility Holdings (53 percent ownership), and Indiana Gas (47 percent ownership). The Ohio operations generally do business as Vectren Energy Delivery of Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services.

2. Summary of Significant Accounting Policies

The interim consolidated condensed 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 consolidated condensed 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, 2010, filed with the Securities and Exchange Commission on February 17, 2011, on Form 10-K. Because of the seasonal nature of the Company's utility 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.

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3. Comprehensive Income

Comprehensive income consists of the following:

(In millions)	Three Months Ended March 31, 2011	2010
Net income	$ 44.6	$ 63.2
Comprehensive income (loss) of unconsolidated affiliates	2.3	(7.1)
Cash flow hedges		
Unrealized losses	0.4	(0.5)
Reclassifications to net income	(3.6)	-
Income taxes	0.3	3.1
Total comprehensive income	$ 44.0	$ 58.7

Accumulated other comprehensive income arising from unconsolidated affiliates is primarily the Company's portion of ProLiance Holdings, LLC's accumulated comprehensive income related to use of cash flow hedges. (See Note 9 for more information on ProLiance.)

4. 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.

(In millions, except per share data)	Three Months Ended March 31, 2011	2010
Numerator:		
Numerator for basic EPS	$ 44.6	$ 63.1
Add back earnings attributable to participating securities	-	0.1
Reported net income (Numerator for Diluted EPS)	$ 44.6	$ 63.2
Denominator:		
Weighted average common shares outstanding (Basic EPS)	81.7	81.0
	-	0.2

Conversion of share based compensation arrangements				
Adjusted weighted average shares outstanding and assumed conversions outstanding (Diluted EPS)		81.7		81.2
Basic EPS	$	0.55	$	0.78
Diluted EPS	$	0.55	$	0.78

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For the three months ended March 31, 2011, options to purchase 288,320 additional shares of the Company's common stock were outstanding, but were not included in the computation of diluted EPS because their effect would be antidilutive, compared to 517,800 shares for the three months ended March 31, 2010. The exercise prices for these options ranged from $26.63 to $27.15 for the three months ended March 31, 2011, compared to $24.74 to $27.15 for the three months ended March 31, 2010.

5. Acquisition of Minnesota Limited, Inc.

On March 31, 2011, the Company, through its wholly owned subsidiary Vectren Infrastructure Services Company, Inc, purchased Minnesota Limited, Inc., excluding certain assets. Minnesota Limited is a specialty contractor focusing on transmission pipeline construction and maintenance; pump station, compressor station, terminal and refinery construction; gas distribution; and hydrostatic testing. Minnesota Limited, headquartered in Big Lake, Minnesota, has approximately 500 employees and is licensed to operate in about 40 states and the majority of its customers are generally located in the northern Midwest region.

Along with the Company's wholly owned subsidiary, Miller Pipeline LLC, Minnesota Limited is included in the Company's nonutility Infrastructure Services operating segment. This acquisition positions the Company for anticipated growth in demand for gas transmission construction resulting from the need to transport new sources of natural gas and oil found in shale formations and the need to upgrade the nation's aging pipelines.

The Company accounted for the cash acquisition in accordance with FASB authoritative guidance for business combinations, which requires the Company to recognize 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 March 31, 2011:

(In millions)		
Working capital assets	$	21.1
Working capital liabilities		(6.7)
Net Working Capital		14.4
Property, plant & equipment		34.4
Identifiable intangible assets		19.2
Goodwill		20.3
Net assets acquired		88.3
Debt obligation & accrued interest assumed		(5.4)
Cash paid in acquisition, net of cash acquired	$	82.9

As of May 5, 2011, the purchase price and its allocation remain preliminary and could change in subsequent periods. Any subsequent material changes to the purchase price and its allocation will be adjusted pursuant to FASB guidance. The final purchase price and the allocation are dependent on final reconciliations of working capital, and finalization of appraisals for property, plant, and equipment and identifiable intangible assets, among other items.

Level 3 market inputs, such as discounted cash flows, revenue growth rates, royalty rates, and dealer and auction values of used equipment, were used to derive the preliminary fair values of the identifiable intangible assets and property plant and equipment. Identifiable intangible assets include back log, long-term customer relationships, and trade name. The Company intends to use the acquired assets for an extended period and will amortize them on a straight-line basis over their estimated useful lives. 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 synergies from more efficient utilization of equipment and human resources within the combined entities 2) the experience and size of the acquired work force; and 3) the reputation of the current Minnesota Limited management team. The goodwill, which does not amortize pursuant to FASB guidance, is deductible over a 15 year period for purposes of computing current income tax expense.

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Transaction costs associated with the acquisition and expensed by the Company totaled approximately $0.5 million, of which $0.2 million are included in other operating expenses during the three months ended March 31, 2011. As the acquisition was effective on March 31, 2011, only the purchase price allocation, payment for the acquired business, and the transaction costs impacted the Company's consolidated financial statements for the three months ended March 31, 2011.

During the quarter ended March 31, 2011 and 2010, unaudited proforma results of the combined companies assuming the acquisition closed on January 1, 2010 would have added approximately $20 million to consolidated revenues in both periods. Due to the seasonal nature of the acquired business, the impact to net income and earnings per share would have been diminimus. However, 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.

Concurrent with the purchase agreement, the Company executed a lease arrangement at fair value for the Minnesota Limited corporate headquarters, which is owned by a member of the Minnesota Limited management team and certain family members. The lease obligates the Company to pay approximately $83,333 per month for 10 years along with certain executory costs for taxes and other operating expenses. Pursuant to FASB guidance, the Company accounts for the obligation as an operating lease, expensing the lease payments and executory costs as incurred.

6. Retirement Plans & Other Postretirement Benefits

The Company maintains three qualified defined benefit pension plans, a nonqualified supplemental executive retirement plan (SERP), and three other postretirement benefit plans. The defined benefit pension and other postretirement benefit plans, 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 Company has a Voluntary Employee Beneficiary Association (VEBA) Trust Agreement for the partial funding of postretirement health benefits for retirees and their eligible dependents and beneficiaries in one of the three plans. Annual VEBA funding is discretionary; however, no further funding is anticipated. The qualified pension plans and the SERP are aggregated under the heading "Pension Benefits." Other postretirement benefit plans are aggregated under the heading "Other Benefits."

Net Periodic Benefit Costs

A summary of the components of net periodic benefit cost follows:

	Three Months Ended March 31,			
	Pension Benefits		Other Benefits	
(In millions)	2011	2010	2011	2010
Service cost	$ 1.7	$ 1.6	$ 0.1	$ 0.1
Interest cost	4.0	3.9	1.1	1.2
Expected return on plan assets	(5.3)	(4.6)	-	(0.1)
Amortization of prior service cost	0.4	0.4	(0.2)	(0.2)
Amortization of transitional obligation	-	-	0.3	0.3
Amortization of actuarial loss	1.0	0.5	0.1	0.1
Net periodic benefit cost	$ 1.8	$ 1.8	$ 1.4	$ 1.4

Employer Contributions to Qualified Pension Plans
Currently, the Company expects to contribute approximately $35 million to its pension plan trusts for 2011. During the three months ended March 31, 2011, contributions of $27.7 million have been made.

7. 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 as a component of operating revenues, which totaled $11.1 million and $15.3 million in the three months ended March 31, 2011 and 2010, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

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8. Supplemental Cash Flow Information

As of March 31, 2011 and December 31, 2010, the Company has accruals related to utility and nonutility plant purchases totaling approximately $14.7 million and $13.9 million, respectively.

9. ProLiance Holdings, LLC

ProLiance Holdings, LLC (ProLiance), a nonutility energy marketing affiliate of Vectren and Citizens Energy Group (Citizens), provides services to a broad range of municipalities, utilities, industrial operations, schools, and healthcare institutions located throughout the Midwest and Southeast United States. ProLiance's customers include Vectren's Indiana utilities and nonutility gas supply operations as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. 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.

Summarized Financial Information

(In millions)	Three Months Ended March 31, 2011	2010
Summarized statement of income information:		
Revenues	$ 500.6	$ 538.3
Operating income (loss)	$ (17.2)	$ 14.3
ProLiance's earnings (loss)	$ (17.4)	$ 14.3

(In millions)	As of March 31, 2011	December 31, 2010
Summarized balance sheet information:		
Current assets	$ 276.0	$ 441.4
Noncurrent assets	$ 59.9	$ 59.1
Current liabilities	$ 147.0	$ 298.1
Noncurrent liabilities	$ 0.6	$ 0.4
Members' equity	$ 191.4	$ 208.9
Accumulated other comprehensive income (loss)	$ (7.1)	$ (10.8)
Noncontrolling interest	$ 4.0	$ 3.9

Vectren records its 61 percent share of ProLiance's earnings after income taxes and an interest expense allocation.

Investment in Liberty Gas Storage

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

In late 2008, the project at the North site was halted due to subsurface and well-completion problems, resulting in Liberty recording a $132 million impairment charge related to the North site in 2009. ProLiance recorded its share of the charge in 2009 totaling $33 million; the Company recorded its share of the charge in 2009 totaling $11.9 million after tax in Equity in earnings of unconsolidated affiliates. Development of the South site continues. Approximately 12 Bcf of the storage, which comprises three of the four FERC certified caverns, is fully completed and tested. As a result of the issues encountered at the North site, Liberty has submitted a request to the FERC to separate the North site from the South site. ProLiance's ability to meet the needs of its customers has not, nor does it expect it to be, impacted. As of March 31, 2011 and December 31, 2010, ProLiance's investment in Liberty approximated $36.9 million and $36.7 million respectively.

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Liberty received a Demand for Arbitration from Williams Midstream Natural Gas Liquids, Inc. (“Williams”) on February 8, 2011 related to a Sublease Agreement (“Sublease”) between Liberty and Williams at the North site. Williams alleges that Liberty was negligent in its attempt to convert certain salt caverns to natural gas storage and thereby damaged the caverns. Williams alleges damages of $56.7 million. Liberty believes that it has complied with all of its obligations to Williams, including properly terminating the Sublease. Liberty intends to vigorously defend itself and has asserted counterclaims substantially in excess of the amounts asserted by Williams.

Transactions with ProLiance

Purchases from ProLiance for resale and for injections into storage for the three months ended March 31, 2011 and 2010 totaled $120.1 million and $163.4 million, respectively. Amounts owed to ProLiance at March 31, 2011 and December 31, 2010, for those purchases were $28.5 million and $59.6 million, respectively, and are included in Accounts payable to affiliated companies in the Consolidated Balance Sheets. Vectren received regulatory approval on April 25, 2006, from the IURC for ProLiance to provide natural gas supply services to the Company’s Indiana utilities through March 2011. On March 17, 2011, an order was received by the IURC providing for ProLiance’s continued provision of gas supply services to the Company’s Indiana utilities and Citizens Energy Group through March 2016. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

10. Financing Activities

Utility Holdings Long Term Debt

On April 5, 2011, Utility Holdings entered into a private placement note purchase agreement pursuant to which various institutional investors have agreed to purchase the following tranches of notes: (i) $55 million of 4.67 percent Senior Guaranteed Notes, due November 30, 2021, (ii) $60 million of 5.02 percent Senior Guaranteed Notes, due November 30, 2026, and (iii) $35 million of 5.99 percent Senior Guaranteed Notes, due December 2, 2041. The proceeds received from the issuance of these senior notes will be used to partially refinance $250 million of Utility Holdings long-term debt maturing December 1, 2011. The remainder of the maturing debt will be retired with short-term borrowings. These senior notes are unsecured and will be jointly and severally guaranteed by Utility Holdings’ regulated utility subsidiaries, Southern Indiana Gas and Electric Company, Indiana Gas Company, Inc., and Vectren Energy Delivery of Ohio, Inc. Subject to the satisfaction of customary conditions precedent, this financing is scheduled to close on or about November 30, 2011. The Company has reclassified $150 million of the $250 million debt redemption due in December 2011 to long-term debt in its March 31, 2011 Consolidated Balance Sheet to reflect the Company’s ability and intent to refinance that portion of the debt with this issuance.

11. Commitments & Contingencies

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 March 31, 2011, parent level guarantees support a maximum of $25 million of ESG’s performance contracting commitments and warranty obligations and $37 million of other project guarantees. The broader scope of ESG’s performance contracting obligations, including those not guaranteed by the parent company, are described below. In addition, the parent company has approximately $85 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $57 million support the operations of Vectren Source, a wholly owned non-regulated retail gas marketer and $21 million represent letters of credit supporting other nonutility operations. Guarantees issued and outstanding on behalf of unconsolidated affiliates approximated $3 million at March 31, 2011. These guarantees relate primarily to arrangements between ProLiance and various natural gas pipeline operators. The Company has not been called upon to satisfy any obligations pursuant to these parental guarantees and has accrued no significant liabilities related to these guarantees.

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Performance Guarantees & Product Warranties
In the normal course of business, ESG, Miller, and other wholly owned subsidiaries 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 March 31, 2011, there are 75 open surety bonds supporting future performance. The average face amount of these obligations is $4.0 million, and the largest obligation has a face amount of $30.4 million. The maximum exposure of these obligations is less than these amounts for several factors, including the level of work already completed. At March 31, 2011, over 50 percent of work was completed on projects with open surety bonds. A significant portion of these commitments will be fulfilled within one year. In instances where ESG operates facilities, project guarantees extend over a longer period. In addition to its performance obligations, ESG also warrants the functionality of certain installed infrastructure generally for one year and the associated energy savings over a specified number of years. The Company has no significant accruals for these warranty obligations as of March 31, 2011.

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. Environmental Matters

Indiana Senate Bill 251
In April 2011, the Indiana legislature passed Senate Bill 251. The legislation is comprehensive energy legislation that was passed in response to Indiana's forecasted energy needs. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard that may have substantial impact on the Company. While the legislation is not yet law, it is anticipated the legislation will be signed by the governor in the near term.

The legislation would apply to several proposed federal mandates/regulations concerning the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution, including greenhouse gas emissions, among others. The legislation provides a framework to recover 80 percent of federally mandated costs, which include construction, depreciation, operating and other costs, through a periodic rate adjustment mechanism outside of a base rate increase and 20 percent of those costs to be deferred until the utility's next general rate case. The legislation therefore provides some certainty of recovery of costs associated with implementing the laws and regulations below.

The legislation establishes a voluntary clean energy portfolio standard that provides incentives to 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 its Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. 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 interconnected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. The Company believes that SIGECO, as a result of these actions, is already at approximately 5 percent compared to the 10 percent 2025 goal.

Clean Air Act

The Clean Air Interstate Rule (CAIR) is 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. On July 11, 2008, the US Court of Appeals for the District of Columbia vacated the federal CAIR regulations. Various parties filed motions for reconsideration, and on December 23, 2008, the Court reinstated the CAIR regulations and remanded the regulations back to the EPA for promulgation of revisions in accordance with the Court's July 11, 2008 order. Thus, the original version of CAIR promulgated in March of 2005 remains effective while EPA revises it per the Court's guidance. SIGECO is in compliance with the current CAIR Phase I annual NOx reduction requirements in effect on January 1, 2009, and the Phase I annual SO2 reduction requirements in effect on January 1, 2010. Utilization of the Company's inventory of NOx and SO2 allowances may also be impacted if CAIR is further revised. 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.

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Similarly, in March of 2005, EPA promulgated the Clean Air Mercury Rule (CAMR). CAMR is an allowance cap and trade program requiring further reductions in mercury emissions from coal-burning power plants. The CAMR regulations were vacated by the US Court of Appeals for the DC Circuit in July 2008. In response to the court decision, EPA announced that it intended to publish proposed Maximum Achievable Control Technology standards for mercury in 2011. In March 2011, the EPA released its proposed Hazardous Air Pollutants (HAPs) rule for the reduction of mercury, non-mercury particulate and acid gases. Based on initial review of the proposed regulation, the Company believes that it will be able to meet these new stringent emission reduction limits with its existing suite of pollution control equipment.

To comply with Indiana's implementation plan of the Clean Air Act of 1990, the CAIR regulations, and to comply with potential future regulations of mercury and further NOx and SO2 reductions, SIGECO has IURC authority to invest in clean coal technology. Using this authorization, SIGECO has invested approximately $411 million in pollution control equipment, including Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order recently obtained April 27, 2011.

SIGECO's coal fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx. On July 6, 2010, the EPA issued its proposed revisions to CAIR, renamed the Clean Air Transport Rule, for public comment. The Transport Rule proposes a 71 percent reduction of SO2 over 2005 national levels and a 52 percent reduction of NOx over 2005 national levels and would further impact the utilization of currently granted SO2 and NOx allowances. Based upon an initial review of this proposed Clean Air Transport Rule, the Company believes that it will be able to meet these new emission reduction limits with its existing suite of pollution control equipment.

Climate Change

In April of 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April of 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December of 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. Therefore, any new regulations would likely also impact major stationary sources of greenhouse gases. The EPA has promulgated two greenhouse gas regulations that apply to SIGECO's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which will require reporting of emissions beginning in 2011 (for the emission year 2010). The EPA has also recently 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 greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility.

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

Impact of Legislative Actions & Other Initiatives is Unknown

If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas 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 greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251. Customer rates may also be impacted should decisions be made to reduce the level of sales to municipal and other wholesale customers in order to meet emission targets.

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Ash Ponds & Coal Ash Disposal Regulations

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 EPA did not offer a preferred alternative, but is taking public comment on multiple alternative regulations. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. The alternatives include regulating coal combustion by-products as hazardous waste. At this time, the majority of the Company’s ash is being beneficially reused. The proposals offered by EPA allow for the beneficial reuse of ash in certain circumstances. Costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Clean Water Act

Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” to minimize adverse environmental impacts. 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 of 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. Depending upon the approaches taken by the EPA when it reissues the regulation, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. 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 the state to determine whether cooling towers should be required on a case by case basis. Similarly, costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Environmental Remediation Efforts

In the past, Indiana Gas, SIGECO, and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable 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 at these sites.

Indiana Gas identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas completed a remedial investigation/feasibility study (RI/FS) 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. Indiana Gas submitted the remainder of the sites to the IDEM's Voluntary Remediation Program (VRP) and is currently conducting some level of remedial activities, including groundwater monitoring at certain sites, where deemed appropriate, and will continue remedial activities at the sites as appropriate and necessary.

Indiana Gas 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, Indiana Gas has recorded cumulative costs that it reasonably expects to incur totaling approximately $23.2 million. The estimated accrued costs are limited to Indiana Gas’ share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which limit Indiana Gas’ costs at these 19 sites to between 28 percent and 50 percent. 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.

In October 2002, SIGECO received a formal information request letter from the IDEM regarding five manufactured gas plants that it owned and/or operated and were not enrolled in the IDEM's VRP. In October 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO added those four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. That renewal was approved by the IDEM in February 2004. SIGECO was also named in a lawsuit, involving another waste disposal site subject to potential environmental remediation efforts. With respect to that lawsuit, SIGECO settled with the plaintiff during 2010 mitigating any future claims at this site. SIGECO has filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or related to the site subject to the recently settled lawsuit. In November the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue.

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SIGECO has recorded cumulative costs that it reasonably expects to incur related to these environmental matters, including the recent settlement discussed above, totaling approximately $15.8 million. However, the total costs that may be incurred in connection with addressing all of these sites cannot be determined at this time. With respect to insurance coverage, SIGECO has recorded approximately $14.1 million of expected insurance recoveries from certain of its insurance carriers under insurance policies in effect when these sites were in operation. While negotiations are ongoing with certain carriers, settlements have been reached with some carriers and $8.7 million in proceeds have been received.

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 some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2011 and December 31, 2010, respectively, approximately $5.0 million and $5.5 million of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and SIGECO sites.

13. Rate & Regulatory Matters

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. On July 30, 2010, Vectren South revised downward its increase requested through the filing of its rebuttal position to approximately $34 million. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 2, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions will be initiated.

Vectren South Electric Demand Side Management Program Filing

On August 16, 2010, Vectren South 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 are 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, including 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.

In its August filing, Vectren South proposed a three-year DSM Plan that expands its current portfolio of Core and Core Plus DSM Programs in order to meet the energy savings goals established by the IURC. Vectren South requested recovery of these program costs under a current tracking mechanism. In addition, Vectren South proposed a performance incentive mechanism that is contingent upon the success of each of the DSM Programs in reducing energy usage to the levels defined by the IURC. This performance incentive would also be recovered in the same tracking mechanism. Finally, the Company proposed lost margin recovery associated with the implementation of DSM programs for large customers, and cited its decoupling proposal applicable to residential and general service customers in the pending electric base rate case. On January 20, 2011, the OUCC and Vectren South filed a settlement with the IURC reflecting agreement on the Company's programs and lost margin recovery from large customers. A hearing was held on March 8, 2011 involving all parties to this proceeding. A proposed order was submitted by the Settling Parties on March 29, 2011, and on April 19, 2011, the Commercial and Industrial Group submitted exceptions to the proposed order. A response by the Settling Parties was filed April 26, 2011, which means the issue is fully briefed and is now before the IURC to issue a final order. As an alternative to the Company's electric decoupling proposal that was denied by the IURC in the order received April 27, 2011, the settlement also provides that margins lost from residential and commercial customers due to energy efficiency programs may be deferred for future recovery under a rate mechanism to be proposed by the Company. Subject to the approval of that settlement by the IURC, the Company expects to propose such a mechanism.

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Vectren North & Vectren South Gas Decoupling Extension Filing

On April 14, 2011, the Company's Indiana based gas companies (Vectren North and Vectren South) filed with the IURC a joint settlement agreement with the OUCC on an extension of the offering of conservation programs and the supporting gas decoupling mechanism originally approved in December 2006. The settlement provides for new program offerings and the extension of the current decoupling mechanism through December 2015. Program costs will continue to be recovered through a periodic tracker mechanism. A prehearing conference has been scheduled by the IURC for May 9, 2011, at which time a formal procedural schedule will be issued. An order is anticipated sometime during 2011.

VEDO Gas Rate Design

The rate design approved by the PUCO on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design, which places substantially all of the fixed cost recovery in the monthly customer service charge. This rate design mitigates most weather risk as well as the effects of declining usage, similar to the company's lost margin recovery mechanism in place in the Indiana natural gas service territories and the mechanism in place in Ohio prior to this rate order. Since the straight fixed variable rate design was fully implemented in February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge. As a result, some margin previously recovered during the peak delivery winter months, such as January and the first half of February 2010, is more ratably recognized throughout the year.

In addition in 2010, the Company began recognizing a return on and of investments made to replace distribution risers and bare steel and cast iron infrastructure per a PUCO order.

VEDO Continues the Process to Exit the Merchant Function

On August 20, 2008, the PUCO approved the results of an auction selecting qualified wholesale suppliers to provide the gas commodity to the Company for resale to its customers at auction-determined standard pricing. This standard pricing was comprised of the monthly NYMEX settlement price plus a fixed adder. This standard pricing, which was effective from October 1, 2008 through March 31, 2010, was the initial step in exiting the merchant function in the Company's Ohio service territory. The approach eliminated the need for monthly gas cost recovery (GCR) filings and prospective PUCO GCR audits.

The second phase of the exit process began on April 1, 2010. During this phase, the Company no longer sells natural gas directly to customers. Rather, state-certified Competitive Retail Natural Gas Suppliers, that were successful bidders in a similar regulatory-approved auction, sell the gas commodity to specific customers for a 12 month period at auction-determined standard pricing. The first auction was conducted on January 12, 2010, and the auction results were approved by the PUCO on January 13, 2010. The plan approved by the PUCO required that the Company conduct at least two annual auctions during this phase. As such, the Company conducted another auction on January 18, 2011 in advance of the second 12-month term which commences on April 1, 2011. The results of that auction were approved by the PUCO on January 19, 2011. Vectren Source, the Company's wholly owned nonutility retail gas marketer, was a successful bidder in both auctions winning one tranche of customers in the first auction and two tranches of customers in the second auction. Consistent with current practice, customers will continue to receive a single bill for the commodity as well as the delivery component of natural gas service from VEDO.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition. It, however, has and will continue to reduce Gas utility revenues and have an equal and offsetting impact to Cost of gas sold and revenue related taxes recorded in Taxes other than income taxes as VEDO no longer purchases gas for resale to these customers.

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14. Fair Value Measurements

The carrying values and estimated fair values of the Company's other financial instruments follow:

	March 31, 2011		December 31, 2010	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,720.8	$1,842.1	$1,715.9	$1,841.2
Short-term borrowings & notes payable	122.3	122.3	118.3	118.3
Cash & cash equivalents	34.5	34.5	10.4	10.4

For the balance sheet dates presented in these financial statements, other than $20.0 million invested in money market funds and included in Cash and cash equivalents as of March 31, 2011, the Company had no material assets or liabilities recorded at fair value outstanding, and, other than the assets and liabilities acquired in the transaction described in Note 5, no material assets or liabilities valued using Level 2 or Level 3 inputs. The money market investments were valued using Level 1 inputs.

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 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 would not be expected to have a material effect on the Company's results of operations.

Because of the customized nature of notes receivable investments and lack of a readily available market, it is not practical to estimate the fair value of these financial instruments at specific dates without considerable effort and cost. At March 31, 2011 and December 31, 2010, the fair value for these financial instruments was not estimated. The carrying value of notes receivable, inclusive of any accrued interest and net of impairment reserves, was approximately $10.9 million at March 31, 2011 and December 31, 2010.

The fair value table in Note 18 of the financial statements in the 2010 Form 10-K excluded the estimated fair value of a long-term debt instrument. The chart above now includes the amount and reflects an increase in the estimated fair value of long-term debt of approximately $73.9 million. This change in the disclosed fair value of long-term debt had no effect on the carrying value of debt included in the consolidated balance sheet.

15. 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 is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Shared Service operations.

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Consistent with a reporting structure implemented during 2010, the Nonutility Group is comprised of five operating segments. Prior segment disclosures reported the Nonutility Group as a single operating segment, and for comparison purposes those prior periods are conformed to the current year presentation. The operating segments of the Nonutility Group are Infrastructure Services, Energy Services, Coal Mining, Energy Marketing, and Other Businesses.

Corporate and Other includes unallocated corporate expenses such as advertising and charitable contributions, among other activities, that benefit the Company's other operating segments.

Net income is the measure of profitability used by management for all operations.

The acquisition of Minnesota Limited was completed on March 31, 2011 (See Note 5) and as such the only impact to the segment information that follows relates to minor transaction fees expensed during the current reporting period. Information related to the Company's business segments is summarized below:

	Three Months Ended March 31,	
(In millions)	2011	2010
Revenues		
Utility Group		
Gas Utility Services	$356.7	$468.1
Electric Utility Services	146.4	144.9
Other Operations	11.0	11.1
Eliminations	(10.5)	(10.7)
Total Utility Group	503.6	613.4
Nonutility Group		
Infrastructure Services	47.2	35.3
Energy Services	23.6	24.1
Coal Mining	69.4	52.1
Energy Marketing	74.0	73.2
Total Nonutility Group	214.2	184.7
Eliminations	(35.2)	(57.8)
Consolidated Revenues	$682.6	$740.3
Profitability Measure - Net Income (Loss)		
Utility Group		
Gas Utility Services	$36.1	$39.7
Electric Utility Services	8.6	12.4
Other Operations	3.9	3.3
Utility Group Net Income	48.6	55.4
Nonutility Group Net Income (Loss)		
Infrastructure Services	(2.9)	(3.0)
Energy Services	(1.4)	(0.3)
Coal Mining	1.6	3.9
Energy Marketing	(0.4)	10.2
Other Businesses	(0.3)	(3.0)
Nonutility Group Net Income (Loss)	(3.4)	7.8
Corporate & Other Group Net Income (Loss)	(0.6)	-
Consolidated Net Income	$44.6	$63.2

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

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

Indiana Gas provides energy delivery services to approximately 570,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 142,000 electric customers and approximately 111,000 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. The Ohio operations provide energy delivery services to over 314,000 natural gas customers located near Dayton in west central Ohio. The Ohio operations are owned as a tenancy in common by Vectren Energy Delivery of Ohio, Inc. (VEDO), a wholly owned subsidiary of Utility Holdings (53 percent ownership), and Indiana Gas (47 percent ownership). The Ohio operations generally do business as Vectren Energy Delivery of Ohio.

The Company, through Vectren Enterprises, Inc. (Enterprises), is involved in nonutility activities in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair services. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. Enterprises also has other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. All of the above are collectively referred to as the Nonutility Group. Enterprises supports the Company’s regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services.

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. Nonutility Group operations are discussed below as primary operations and other operations. Primary nonutility operations denote areas of management’s forward looking focus.

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 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.

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 2010 annual report filed on Form 10-K.

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Summary results for the three months ended March 31, 2011 follow:

(In millions, except per share data)	Three Months Ended March 31, 2011	2010
Net income	$44.6	$63.2
Attributed to:		
Utility Group	48.6	55.4
Nonutility Group	(3.4)	7.8
Corporate & other	(0.6)	-
Basic EPS	$0.55	$0.78
Attributed to:		
Utility Group	0.59	0.68
Nonutility Group	(0.04)	0.10
Corporate & other	-	-

Utility Group

In 2011, the Utility Group's first quarter earnings were $48.6 million compared to $55.4 million in 2010, a decrease of $6.8 million. The decrease results from the impact of rate design changes implemented in February 2010 in the Ohio service territory and increased operating expenses associated with planned electric generating maintenance activities.

Nonutility Group

In 2011, the Nonutility Group incurred a net loss of $3.4 million, which compares to net income of $7.8 million in 2010. ProLiance results, which were a loss of $7.5 million in 2011 and earnings of $3.9 million in 2010, were the primary driver of the decrease.

Dividends

Dividends declared for the three months ended March 31, 2011 were $0.345 per share, compared to $0.340 per share for the same period in 2010.

Use of Non-GAAP Performance Measures and Per Share Measures

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

GAAP.

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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 Consolidated Statements of Income.

Results of Operations of the Utility Group

The Utility Group is comprised of Utility Holdings' operations and consists of the Company's regulated 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 primarily to southwestern Indiana, and the Company's 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 months ended March 31, 2011 and 2010 follow:

	Three Months Ended March 31,	
(In millions, except per share data)	2011	2010
OPERATING REVENUES		
Gas utility	$ 356.7	$ 468.1
Electric utility	146.4	144.9
Other	0.5	0.4
Total operating revenues	503.6	613.4
OPERATING EXPENSES		
Cost of gas sold	195.1	297.8
Cost of fuel & purchased power	59.5	58.0
Other operating	86.9	81.6
Depreciation & amortization	48.2	46.5
Taxes other than income taxes	18.0	22.3
Total operating expenses	407.7	506.2
OPERATING INCOME	95.9	107.2
OTHER INCOME - NET	1.7	2.2
INTEREST EXPENSE	20.4	20.3
INCOME BEFORE INCOME TAXES	77.2	89.1
INCOME TAXES	28.6	33.7
NET INCOME	$ 48.6	$ 55.4
CONTRIBUTION TO VECTREN BASIC EPS	$ 0.59	$ 0.68

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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, fuel, and purchased power costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. 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 March 31,	
(In millions)	2011	2010
Gas utility revenues	$ 356.7	$ 468.1
Cost of gas sold	195.1	297.8
Total gas utility margin	$ 161.6	$ 170.3
Margin attributed to:		
Residential & commercial customers	$ 139.5	$ 150.0
Industrial customers	17.7	16.2
Other	4.4	4.1
Total gas utility margin	$ 161.6	$ 170.3
Sold & transported volumes in MMDth attributed to:		
Residential & commercial customers	52.8	54.6
Industrial customers	28.8	26.6
Total sold & transported volumes	81.6	81.2

For the three months ended March 31, 2011, gas utility margins were $161.6 million and compared to 2010 decreased $8.7 million. Management estimates a decrease of $3.6 million due to Ohio rate design changes and Ohio weather, as described below. Returns generated on investments in bare steel/ cast iron and distribution riser replacement in Ohio increased margins $0.8 million quarter over quarter. Large customer margin, net of the impacts of regulatory initiatives and tracked costs, increased by $1.5 million due primarily to increased volumes sold, largely from ethanol producers. Margin decreased $5.8 million due to lower revenue taxes and operating costs directly recovered in margin. The remaining decrease is primarily due to lower late fees and recoveries of the gas cost component of Indiana bad debt expense which are impacted by lower gas costs.

The rate design approved by the Public Utilities Commission of Ohio (PUCO) on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design, which places substantially all of the fixed cost recovery in the monthly customer service charge. This rate design mitigates most weather risk as well as the effects of declining usage. Since the straight fixed variable rate design was fully implemented in mid February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge. As a result, margin recognized in the first quarter of 2010 that reflected a volumetric rate design during the peak delivery winter months of January and the first half of February 2010, is now more ratably recognized throughout the year.

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

Electric utility margin and volumes sold by customer type follows:

(In millions)	Three Months Ended March 31, 2011	2010
Electric utility revenues	$ 146.4	$ 144.9
Cost of fuel & purchased power	59.5	58.0
Total electric utility margin	$ 86.9	$ 86.9
Margin attributed to:		
Residential & commercial customers	$ 54.0	$ 55.3
Industrial customers	23.4	22.5
Other customers	1.9	1.7
Subtotal: retail	$ 79.3	$ 79.5
Wholesale power & transmission system margin	7.6	7.4
Total electric utility margin	$ 86.9	$ 86.9
Electric volumes sold in GWh attributed to:		
Residential & commercial customers	681.6	711.9
Industrial customers	661.9	610.4
Other customers	5.9	6.0
Total retail volumes sold	1,349.4	1,328.3

Retail

Electric retail utility margins were $79.3 million for the three months ended March 31, 2011, and were generally flat compared to 2010. Large customer margin increased $0.9 million in the 2011 quarter compared to the prior year. That increase was more than offset by unfavorable weather in the quarter.

Margin from Wholesale Electric Activities

Periodically, generation capacity is in excess of native load. The Company markets and sells this unutilized generating and transmission capacity to optimize the return on its owned assets. Substantially all off-system sales occur into the MISO Day Ahead and Real Time markets. Further detail of Wholesale activity follows:

(In millions)	Three Months Ended March 31, 2011	2010
Off-system sales	$ 2.0	$ 2.6
Transmission system sales	5.6	4.8
Total wholesale margin	$ 7.6	$ 7.4

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. Margin associated with these projects, including the reconciliation of recovery mechanisms, and other transmission system operations, totaled $5.6 million during the three months ended March 31, 2011, compared to $4.8 million for the same period in 2010. The increase in these transmission system sales is principally due to the increased investment in qualifying projects.

One such project currently under construction meeting these expansion plan criteria is an interstate 345 Kv transmission line that will connect Vectren's A.B. Brown Generating Station to a station in Indiana owned by Duke Energy to the north and to a station in Kentucky owned by Big Rivers Electric Corporation to the south. During the construction of these transmission assets and while these assets are in service, SIGECO will recover an approximate 10 percent return, inclusive of the FERC approved equity rate of return of 12.38 percent, on capital investments through a rider mechanism which is projected annually and reconciled the following year based on actual results. Of the total investment, which is expected to approximate $90 million, the Company has invested approximately $61.0 million as of March 31, 2011. The north leg of this expansion was placed in service in November 2010, and the south leg of this project is expected to be operational in 2012.

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For the three months ended March 31, 2011, margin from off-system sales was $2.0 million, compared to $2.6 million for the three months ended March 31, 2010. Margin from off-system sales were unfavorable during the current year quarter compared to the prior year, due largely to the unavailability of generation as a result of a scheduled maintenance outage. Off-system sales totaled 183.9 GWh and 235.4 GWh during the three months ended March 31, 2011 and 2010, respectively. The base rate increase effective August 17, 2007, requires that wholesale margin from off-system sales earned above or below $10.5 million be shared equally with customers as measured on a fiscal year ending in August. Effective with the implementation of new base rates in May 2011, sharing will be based on a $7.5 million level. Results for the periods presented reflect the impact of that sharing.

Utility Group Operating Expenses

Other Operating

For the three months ended March 31, 2011, other operating expenses were $86.9 million, an increase of $5.3 million, compared to 2010. The increase results primarily from a $3.9 million increase in power supply operating costs, including planned maintenance activities. The remaining increase compared to the prior year is primarily timing.

Depreciation & Amortization

Depreciation expense was $48.2 million for the quarter, an increase of $1.7 million compared to 2010. This increase reflects utility capital expenditures placed into service.

Taxes Other Than Income Taxes

Taxes other than income taxes were $18.0 million for the quarter, a decrease of $4.3 million compared to the prior year quarter. The decrease is primarily attributable to lower Ohio excise and usage taxes associated with that territory’s ongoing process of exiting the merchant function. These expenses are offset dollar-for-dollar with lower gas utility revenues.

Other Income-Net

Other income-net reflects income of $1.7 million for the quarter, a decrease of $0.5 million compared to the prior year quarter. The decrease primarily reflects lower Allowance for Funds Used During Construction (AFUDC).

Interest Expense

Interest expense was $20.4 million for the quarter and was generally flat compared to the prior year, and interest expense continues to reflect the current low interest rate environment and less reliance by the Utility Group on short-term borrowings. At March 31, 2011, and 2010, the Utility Group had no short-term borrowings outstanding.

Income Taxes

In 2011, federal and state income taxes were $28.6 million for the quarter, a decrease of $5.1 million compared to the prior year quarter. The decrease is primarily due to lower pre-tax income. The current year period also reflects the favorable impact of revaluing historical deferred taxes as a result of a lower Indiana state tax apportionment.

Environmental Matters

Indiana Senate Bill 251

In April 2011, the Indiana legislature passed Senate Bill 251. The legislation is comprehensive energy legislation that was passed in response to Indiana’s forecasted energy needs. While the bill is broad in scope, it allows for cost recovery outside of a base rate proceeding for federal government mandated projects and provides for a voluntary clean energy portfolio standard that may have substantial impact on the Company. While the legislation is not yet law, it is anticipated the legislation will be signed by the governor in the near term.

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The legislation would apply to several proposed federal mandates/regulations concerning the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution, including greenhouse gas emissions, among others. The legislation provides a framework to recover 80 percent of federally mandated costs, which include construction, depreciation, operating and other costs, through a periodic rate adjustment mechanism outside of a base rate increase and 20 percent of those costs to be deferred until the utility's next general rate case. The legislation therefore provides some certainty of recovery of costs associated with implementing the laws and regulations below.

The legislation establishes a voluntary clean energy portfolio standard that provides incentives to 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 its Indiana retail customers will be provided by clean energy sources, as defined. The financial incentives include an enhanced return on equity and tracking mechanisms to recover program costs. 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 interconnected to the Company's distribution system. In 2009, the Company also executed a long term purchase power commitment for 50 MW of wind energy. These transactions supplement a 30 MW wind energy purchase power agreement executed in 2008. The Company believes that SIGECO, as a result of these actions, is already at approximately 5 percent compared to the 10 percent 2025 goal.

Clean Air Act

The Clean Air Interstate Rule (CAIR) is 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. On July 11, 2008, the US Court of Appeals for the District of Columbia vacated the federal CAIR regulations. Various parties filed motions for reconsideration, and on December 23, 2008, the Court reinstated the CAIR regulations and remanded the regulations back to the EPA for promulgation of revisions in accordance with the Court's July 11, 2008 order. Thus, the original version of CAIR promulgated in March of 2005 remains effective while EPA revises it per the Court's guidance. SIGECO is in compliance with the current CAIR Phase I annual NOx reduction requirements in effect on January 1, 2009, and the Phase I annual SO2 reduction requirements in effect on January 1, 2010. Utilization of the Company's inventory of NOx and SO2 allowances may also be impacted if CAIR is further revised. 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.

Similarly, in March of 2005, EPA promulgated the Clean Air Mercury Rule (CAMR). CAMR is an allowance cap and trade program requiring further reductions in mercury emissions from coal-burning power plants. The CAMR regulations were vacated by the US Court of Appeals for the DC Circuit in July 2008. In response to the court decision, EPA announced that it intended to publish proposed Maximum Achievable Control Technology standards for mercury in 2011. In March 2011, the EPA released its proposed Hazardous Air Pollutants (HAPs) rule for the reduction of mercury, non-mercury particulate and acid gases. Based on initial review of the proposed regulation, the Company believes that it will be able to meet these new stringent emission reduction limits with its existing suite of pollution control equipment.

To comply with Indiana's implementation plan of the Clean Air Act of 1990, the CAIR regulations, and to comply with potential future regulations of mercury and further NOx and SO2 reductions, SIGECO has IURC authority to invest in clean coal technology. Using this authorization, SIGECO has invested approximately $411 million in pollution control equipment, including Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with ALCOA (the Company's portion is 150 MW). SCR technology is the most effective method of reducing NOx emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order recently obtained April 27, 2011.

SIGECO's coal fired generating fleet is 100 percent scrubbed for SO_2 and 90 percent controlled for NO_x. On July 6, 2010, the EPA issued its proposed revisions to CAIR, renamed the Clean Air Transport Rule, for public comment. The Transport Rule proposes a 71 percent reduction of SO_2 over 2005 national levels and a 52 percent reduction of NO_x over 2005 national levels and would further impact the utilization of currently granted SO_2 and NO_x allowances. Based upon an initial review of this proposed Clean Air Transport Rule, the Company believes that it will be able to meet these new emission reduction limits with its existing suite of pollution control equipment.

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Climate Change
In April of 2007, the US Supreme Court determined that greenhouse gases meet the definition of "air pollutant" under the Clean Air Act and ordered the EPA to determine whether greenhouse gas emissions from motor vehicles cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. In April of 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December of 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. Therefore, any new regulations would likely also impact major stationary sources of greenhouse gases. The EPA has promulgated two greenhouse gas regulations that apply to SIGECO's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which will require reporting of emissions beginning in 2011 (for the emission year 2010). The EPA has also recently 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 greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility.

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

Impact of Legislative Actions & Other Initiatives is Unknown
If regulations are enacted by the EPA or other agencies or if legislation requiring reductions in CO2 and other greenhouse gases or legislation mandating a renewable energy portfolio standard is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants, nonutility coal mining operations, and natural gas distribution businesses. At this time and in the absence of final legislation, compliance costs and other effects associated with reductions in greenhouse gas emissions or obtaining renewable energy sources remain uncertain. The Company has gathered preliminary estimates of the costs to control greenhouse gas 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 greenhouse gas emissions. However, these compliance cost estimates are based on highly uncertain assumptions, including allowance prices if a cap and trade approach were employed, and energy efficiency targets. Costs to purchase allowances that cap greenhouse gas emissions or expenditures made to control emissions should be considered a cost of providing electricity, and as such, the Company believes such costs and expenditures would be recoverable from customers through Senate Bill 251. Customer rates may also be impacted should decisions be made to reduce the level of sales to municipal and other wholesale customers in order to meet emission targets.

Ash Ponds & Coal Ash Disposal Regulations
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 EPA did not offer a preferred alternative, but is taking public comment on multiple alternative regulations. The Company estimates capital expenditures to comply could be as much as $30 million, and such expenditures could exceed $100 million if the most stringent of the alternatives is selected. Annual compliance costs could increase slightly or be impacted by as much as $5 million. The alternatives include regulating coal combustion by-products as hazardous waste. At this time, the majority of the Company's ash is being beneficially reused. The proposals offered by EPA allow for the beneficial reuse of ash in certain circumstances. Costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

Clean Water Act

Section 316(b) of the Clean Water Act requires that generating facilities use the “best technology available” to minimize adverse environmental impacts. 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 of 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. Depending upon the approaches taken by the EPA when it reissues the regulation, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. 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 the state to determine whether cooling towers should be required on a case by case basis. Similarly, costs for compliance with these regulations would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above.

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Environmental Remediation Efforts

In the past, Indiana Gas, SIGECO, and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable 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 at these sites.

Indiana Gas identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas completed a remedial investigation/feasibility study (RI/FS) 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. Indiana Gas submitted the remainder of the sites to the IDEM's Voluntary Remediation Program (VRP) and is currently conducting some level of remedial activities, including groundwater monitoring at certain sites, where deemed appropriate, and will continue remedial activities at the sites as appropriate and necessary.

Indiana Gas 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, Indiana Gas has recorded cumulative costs that it reasonably expects to incur totaling approximately $23.2 million. The estimated accrued costs are limited to Indiana Gas’ share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which limit Indiana Gas’ costs at these 19 sites to between 28 percent and 50 percent. 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.

In October 2002, SIGECO received a formal information request letter from the IDEM regarding five manufactured gas plants that it owned and/or operated and were not enrolled in the IDEM’s VRP. In October 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO added those four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. That renewal was approved by the IDEM in February 2004. SIGECO was also named in a lawsuit, involving another waste disposal site subject to potential environmental remediation efforts. With respect to that lawsuit, SIGECO settled with the plaintiff during 2010 mitigating any future claims at this site. SIGECO has filed a declaratory judgment action against its insurance carriers seeking a judgment finding its carriers liable under the policies for coverage of further investigation and any necessary remediation costs that SIGECO may accrue under the VRP program and/or related to the site subject to the recently settled lawsuit. In November the Court ruled on two motions for summary judgment, finding for SIGECO and against certain insurers on indemnification and defense obligations in the policies at issue.

SIGECO has recorded cumulative costs that it reasonably expects to incur related to these environmental matters, including the recent settlement discussed above, totaling approximately $15.8 million. However, the total costs that may be incurred in connection with addressing all of these sites cannot be determined at this time. With respect to insurance coverage, SIGECO has recorded approximately $14.1 million of expected insurance recoveries from certain of its insurance carriers under insurance policies in effect when these sites were in operation. While negotiations are ongoing with certain carriers, settlements have been reached with some carriers and $8.7 million in proceeds have been received.

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 some level of additional remedial activities which are not presently foreseen and those costs may not be subject to PRP or insurance recovery. As of March 31, 2011 and December 31, 2010, respectively, approximately $5.0 million and $5.5 million of accrued, but not yet spent, costs are included in Other Liabilities related to both the Indiana Gas and SIGECO sites.

Rate & Regulatory Matters

Vectren South Electric Base Rate Filing

On December 11, 2009, Vectren South filed a request with the IURC to adjust its base electric rates. The requested increase in base rates addressed capital investments, a modified electric rate design that would facilitate a partnership between Vectren South and customers to pursue energy efficiency and conservation, and new energy efficiency programs to complement those currently offered for natural gas customers. On July 30, 2010, Vectren South revised downward its increase requested through the filing of its rebuttal position to approximately $34 million. The IURC issued an order in the case on April 27, 2011. The order provides for an approximate $28.6 million revenue increase to recover costs associated with approximately $325 million in system upgrades that were completed in the three years leading up to the December 2009 filing and modest increases in maintenance and operating expenses. The approved revenue increase is based on rate base of $1,295.6 million, return on equity of 10.4 percent and an overall rate of return of 7.29 percent. The new rates were effective May 2, 2011. The IURC, in its order, denied the Company's request for implementation of the decoupled rate design, which is discussed further below. Finally, addressing issues raised in the case concerning coal supply contracts and related costs, the IURC found that current coal contracts remain effective and that a prospective review process of future procurement decisions will be initiated.

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Vectren South Electric Demand Side Management Program Filing

On August 16, 2010, Vectren South 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 are 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, including 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.

In its August filing, Vectren South proposed a three-year DSM Plan that expands its current portfolio of Core and Core Plus DSM Programs in order to meet the energy savings goals established by the IURC. Vectren South requested recovery of these program costs under a current tracking mechanism. In addition, Vectren South proposed a performance incentive mechanism that is contingent upon the success of each of the DSM Programs in reducing energy usage to the levels defined by the IURC. This performance incentive would also be recovered in the same tracking mechanism. Finally, the Company proposed lost margin recovery associated with the implementation of DSM programs for large customers, and cited its decoupling proposal applicable to residential and general service customers in the pending electric base rate case. On January 20, 2011, the OUCC and Vectren South filed a settlement with the IURC reflecting agreement on the Company's programs and lost margin recovery from large customers. A hearing was held on March 8, 2011 involving all parties to this proceeding. A proposed order was submitted by the Settling Parties on March 29, 2011, and on April 19, 2011, the Commercial and Industrial Group submitted exceptions to the proposed order. A response by the Settling Parties was filed April 26, 2011, which means the issue is fully briefed and is now before the IURC to issue a final order. As an alternative to the Company's electric decoupling proposal that was denied by the IURC in the order received April 27, 2011, the settlement also provides that margins lost from residential and commercial customers due to energy efficiency programs may be deferred for future recovery under a rate mechanism to be proposed by the Company. Subject to the approval of that settlement by the IURC, the Company expects to propose such a mechanism.

Vectren North & Vectren South Gas Decoupling Extension Filing

On April 14, 2011, the Company's Indiana based gas companies (Vectren North and Vectren South) filed with the IURC a joint settlement agreement with the OUCC on an extension of the offering of conservation programs and the supporting gas decoupling mechanism originally approved in December 2006. The settlement provides for new program offerings and the extension of the current decoupling mechanism through December 2015. Program costs will continue to be recovered through a periodic tracker mechanism. A prehearing conference has been scheduled by the IURC for May 9, 2011, at which time a formal procedural schedule will be issued. An order is anticipated sometime during 2011.

VEDO Gas Rate Design

The rate design approved by the PUCO on January 7, 2009, and initially implemented on February 22, 2009, allowed for the phased movement toward a straight fixed variable rate design, which places substantially all of the fixed cost recovery in the monthly customer service charge. This rate design mitigates most weather risk as well as the effects of declining usage, similar to the company's lost margin recovery mechanism in place in the Indiana natural gas service territories and the mechanism in place in Ohio prior to this rate order. Since the straight fixed variable rate design was fully implemented in February 2010, nearly 90 percent of the combined residential and commercial base rate gas margins were recovered through the customer service charge. As a result, some margin previously recovered during the peak delivery winter months, such as January and the first half of February 2010, is more ratably recognized throughout the year.

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In addition in 2010, the Company began recognizing a return on and of investments made to replace distribution risers and bare steel and cast iron infrastructure per a PUCO order.

VEDO Continues the Process to Exit the Merchant Function

On August 20, 2008, the PUCO approved the results of an auction selecting qualified wholesale suppliers to provide the gas commodity to the Company for resale to its customers at auction-determined standard pricing. This standard pricing was comprised of the monthly NYMEX settlement price plus a fixed adder. This standard pricing, which was effective from October 1, 2008 through March 31, 2010, was the initial step in exiting the merchant function in the Company's Ohio service territory. The approach eliminated the need for monthly gas cost recovery (GCR) filings and prospective PUCO GCR audits.

The second phase of the exit process began on April 1, 2010. During this phase, the Company no longer sells natural gas directly to customers. Rather, state-certified Competitive Retail Natural Gas Suppliers, that were successful bidders in a similar regulatory-approved auction, sell the gas commodity to specific customers for a 12 month period at auction-determined standard pricing. The first auction was conducted on January 12, 2010, and the auction results were approved by the PUCO on January 13, 2010. The plan approved by the PUCO required that the Company conduct at least two annual auctions during this phase. As such, the Company conducted another auction on January 18, 2011 in advance of the second 12-month term which commences on April 1, 2011. The results of that auction were approved by the PUCO on January 19, 2011. Vectren Source, the Company's wholly owned nonutility retail gas marketer, was a successful bidder in both auctions winning one tranche of customers in the first auction and two tranches of customers in the second auction. Consistent with current practice, customers will continue to receive a single bill for the commodity as well as the delivery component of natural gas service from VEDO.

The PUCO provided for an Exit Transition Cost rider, which allows the Company to recover costs associated with the transition process. Exiting the merchant function has not had a material impact on earnings or financial condition. It, however, has and will continue to reduce Gas utility revenues and have an equal and offsetting impact to Cost of gas sold and revenue related taxes recorded in Taxes other than income taxes as VEDO no longer purchases gas for resale to these customers. In the three months ended March 31, 2010, VEDO's gas costs and revenue taxes were $82.8 million and $8.6 million, respectively. In the three months ended March 31, 2011, gas costs and revenue taxes were $7.2 millions and $4.8 million, repsectively. Therefore, the year over year decrease in Gas utility revenues resulting from VEDO's exit of the merchant function approximates $79.4 million.

Results of Operations of the Nonutility Group

The Nonutility Group operates in four primary business areas: Infrastructure Services, Energy Services, Coal Mining, and Energy Marketing. Infrastructure Services provides underground construction and repair. Energy Services provides performance contracting and renewable energy services. Coal Mining mines and sells coal. Energy Marketing markets and supplies natural gas and provides energy management services. There are also other legacy businesses that have invested in energy-related opportunities and services, real estate, and leveraged leases, among other investments. The Nonutility Group supports the Company's regulated utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services. Nonutility Group earnings for the three months ended March 31, 2011 and 2010 follow:

	Three Months Ended March 31,	
(In millions, except per share amounts)	2011	2010
NET INCOME (LOSS)	$ (3.4)	$ 7.8

CONTRIBUTION TO VECTREN BASIC EPS	$ (0.04)	$ 0.10
NET INCOME (LOSS) ATTRIBUTED TO:		
Infrastructure Services	$ (2.9)	$ (3.0)
Energy Services	(1.4)	(0.3)
Coal Mining	1.6	3.9
Energy Marketing	(0.4)	10.2
Other Businesses	(0.3)	