VECTREN CORP
Form 10-Q
August 04, 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 June 30, 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

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	81,783,019	July 31, 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	MW: megawatts
FASB: Financial Accounting Standards Board	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FERC: Federal Energy Regulatory Commission	OUCC: Indiana Office of the Utility Consumer Counselor
IDEM: Indiana Department of Environmental Management	PUCO: Public Utilities Commission of Ohio
IURC: Indiana Utility Regulatory Commission	EPA: Environmental Protection Agency
BCF: billions of cubic feet	Throughput: combined gas sales and gas transportation volumes
MISO: Midwest Independent System Operator	XBRL: eXtensible Business Reporting Language
MSHA: Mine Safety and Health Administration	

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	June 30, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash & cash equivalents	$14.8	$10.4
Accounts receivable - less reserves of $7.6 & $5.3, respectively	179.0	176.6
Accrued unbilled revenues	62.6	162.0
Inventories	166.6	187.1
Recoverable fuel & natural gas costs	9.2	7.9
Prepayments & other current assets	80.6	101.2
Total current assets	512.8	645.2
Utility Plant		
Original cost	4,890.0	4,791.7
Less: accumulated depreciation & amortization	1,897.3	1,836.3
Net utility plant	2,992.7	2,955.4
Investments in unconsolidated affiliates	114.8	135.2
Other utility & corporate investments	36.1	34.1
Other nonutility investments	41.2	40.9
Nonutility plant - net	536.0	488.3
Goodwill - net	262.2	242.0
Regulatory assets	173.3	189.4
Other assets	51.0	33.7
TOTAL ASSETS	$4,720.1	$4,764.2

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

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

	June 30, 2011	December 31, 2010
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$119.1	$183.7
Accounts payable to affiliated companies	27.7	59.6
Accrued liabilities	184.5	178.4
Short-term borrowings	144.5	118.3
Current maturities of long-term debt	138.3	250.7
Long-term debt subject to tender	30.0	30.0
Total current liabilities	644.1	820.7
Long-term Debt - Net of Current Maturities & Debt Subject to Tender	1,551.4	1,435.2
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	538.1	515.3
Regulatory liabilities	337.6	333.5
Deferred credits & other liabilities	202.6	220.6
Total deferred credits & other liabilities	1,078.3	1,069.4
Commitments & Contingencies (Notes 11-13)		
Common Shareholders' Equity		
Common stock (no par value) – issued & outstanding 81.8 & 81.7 shares, respectively	687.6	683.4
Retained earnings	762.5	759.9
Accumulated other comprehensive income (loss)	(3.8)	(4.4)
Total common shareholders' equity	1,446.3	1,438.9
TOTAL LIABILITIES & SHAREHOLDERS' EQUITY	$4,720.1	$4,764.2

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
OPERATING REVENUES				
Gas utility	$134.0	$122.9	$490.7	$591.0
Electric utility	159.3	151.0	305.7	295.9
Nonutility	182.5	128.5	362.0	255.8
Total operating revenues	475.8	402.4	1,158.4	1,142.7
OPERATING EXPENSES				
Cost of gas sold	48.8	41.5	243.9	339.3
Cost of fuel & purchased power	60.3	57.8	119.8	115.8
Cost of nonutility revenues	68.5	49.4	173.6	109.9
Other operating	163.3	132.3	304.9	261.2
Depreciation & amortization	61.2	57.2	120.3	113.0
Taxes other than income taxes	12.1	12.1	31.0	35.2
Total operating expenses	414.2	350.3	993.5	974.4
OPERATING INCOME	61.6	52.1	164.9	168.3
OTHER INCOME (EXPENSE)				
Equity in (losses) of unconsolidated affiliates	(12.0)	(13.9)	(22.9)	(5.7)
Other income – net	2.8	0.9	5.2	0.4
Total other income (expense)	(9.2)	(13.0)	(17.7)	(5.3)
INTEREST EXPENSE	27.0	26.0	53.6	52.0
INCOME BEFORE INCOME TAXES	25.4	13.1	93.6	111.0
INCOME TAXES	10.3	4.4	33.9	39.1
NET INCOME	$15.1	$8.7	$59.7	$71.9
AVERAGE COMMON SHARES OUTSTANDING	81.7	81.0	81.7	81.0
DILUTED COMMON SHARES OUTSTANDING	81.8	81.2	81.8	81.2
EARNINGS PER SHARE OF COMMON STOCK:				
BASIC	$0.19	$0.11	$0.73	$0.89
DILUTED	$0.18	$0.11	$0.73	$0.89
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$0.345	$0.340	$0.690	$0.680

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

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

	Six Months Ended June 30,	
	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$59.7	$71.9
Adjustments to reconcile net income to cash from operating activities:		
Depreciation & amortization	120.3	113.0
Deferred income taxes & investment tax credits	34.1	17.6
Equity in losses of unconsolidated affiliates	22.9	5.7
Provision for uncollectible accounts	6.9	10.2
Expense portion of pension & postretirement benefit cost	4.5	4.5
Other non-cash charges - net	6.1	14.5
Changes in working capital accounts:		
Accounts receivable & accrued unbilled revenues	111.2	100.0
Inventories	20.5	7.5
Recoverable/refundable fuel & natural gas costs	(1.3)	(24.2)
Prepayments & other current assets	22.6	17.6
Accounts payable, including to affiliated companies	(102.5)	(98.8)
Accrued liabilities	4.6	14.0
Unconsolidated affiliate dividends	0.1	12.2
Employer contributions to pension & postretirement plans	(33.1)	(8.2)
Changes in noncurrent assets	(3.5)	9.5
Changes in noncurrent liabilities	(3.5)	(8.3)
Net cash flows from operating activities	269.6	258.7
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from:		
Dividend reinvestment plan & other common stock issuances	3.6	3.1
Requirements for:		
Dividends on common stock	(56.4)	(55.1)
Retirement of long-term debt	(1.4)	(1.6)
Other financing activities	(1.4)	-
Net change in short-term borrowings	26.2	(67.9)
Net cash flows from financing activities	(29.4)	(121.5)
CASH FLOWS FROM INVESTING ACTIVITIES		
Proceeds from:		
Unconsolidated affiliate distributions	0.5	0.5
Other collections	0.9	6.8
Requirements for:		
Capital expenditures, excluding AFUDC equity	(152.4)	(137.2)
Business acquisition, net of cash acquired	(83.4)	-
Other investments	(1.4)	(2.4)
Net cash flows from investing activities	(235.8)	(132.3)
Net change in cash & cash equivalents	4.4	4.9
Cash & cash equivalents at beginning of period	10.4	11.9
Cash & cash equivalents at end of period	$14.8	$16.8

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

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 565,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 141,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. The Ohio operations provide energy delivery services to over 312,000 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. Basis of Presentation

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.

3. Comprehensive Income

Comprehensive income consists of the following:

(In millions)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Net income	$15.1	$8.7	$59.7	$71.9
Comprehensive income of unconsolidated affiliates	1.1	9.0	3.4	1.9
Cash flow hedges				
Unrealized gains (losses)	0.5	0.7	0.9	0.2
Reclassifications to net income	0.3	-	(3.3)	-
Income taxes	(0.7)	(4.1)	(0.4)	(1.0)
Total comprehensive income	$16.3	$14.3	$60.3	$73.0

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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Numerator:				
Reported net income (Numerator for Basic and Diluted EPS)	$15.1	$8.7	$59.7	$71.9
Denominator:				
Weighted average common shares outstanding (Basic EPS)	81.7	81.0	81.7	81.0
Conversion of share based compensation arrangements	0.1	0.2	0.1	0.2
Adjusted weighted average shares outstanding and assumed conversions outstanding (Diluted EPS)	81.8	81.2	81.8	81.2
Basic EPS	$0.19	$0.11	$0.73	$0.89

Diluted EPS	$0.18	$0.11	$0.73	$0.89

For the three months ended June 30, 2011, all options were dilutive. For the three months ended June 30, 2010, options to purchase 517,800 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. For the six months ended June 30, 2011, options to purchase 1,920 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 six months ended June 30, 2010. The exercise prices for these options were $27.15 for the six months ended June 30, 2011. The exercise prices for these options ranged from $24.74 to $27.15 for the three and six months ended June 30, 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 is headquartered in Big Lake, Minnesota 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.

(In millions)	
Working capital assets	$ 21.5
Working capital liabilities	(6.7)
Net Working Capital	14.8
Property, plant & equipment	34.4
Identifiable intangible assets	19.2
Goodwill	20.2
Net assets acquired	88.6
Debt obligation assumed	(5.2)
Cash paid in acquisition, net of cash acquired	$ 83.4

As of August 4, 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. Since the initial purchase price allocation was disclosed on March 31, 2011, minor adjustments to working capital accounts have been made to the opening balance sheet. The final purchase price and the allocation are dependent on final reconciliations of certain working capital items, and final valuation of 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.

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 six months ended June 30, 2011 and the remainder was expensed in 2010. For the period from April 1, 2011 through June 30, 2011, Minnesota Limited contributed approximately $22.0 million and $0.5 million to the Company's revenue and net income, respectively.

The following table presents the Company's unaudited proforma results of operations for the three months ended June 30, 2010 and six months ended June 30, 2011 and 2010 as if the acquisition had occurred on January 1, 2010.

(In millions, except per share data)	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Nonutility operating revenues	$422.4	$1,158.4	$1,148.6
Net income	$7.8	$59.5	$69.8
Basic earnings per share	$0.10	$0.73	$0.86
Diluted earnings per share	$0.10	$0.73	$0.86

In addition to the incremental revenues and expenses recorded by Minnesota Limited during this period, the proforma financial data for all periods presented contain several adjustments including the following: recording the additional amortization expense from the identifiable intangible assets; adjusting the estimated tax provision of the proforma combined results; and adjusting for the issuance of short-term debt to facilitate the acquisition. The Company prepared the proforma financial information for the combined entities for comparative purposes only, and it 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. 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 $5.5 million and $5.1 million in the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, these taxes totaled $16.6 million and $20.4 million, respectively. Expenses associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

7. 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 June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2011	2010	2011	2010
Service cost	$1.8	$ 1.6	$ 0.2	$ 0.1
Interest cost	4.0	4.0	1.0	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	0.9	0.5	0.2	0.1
Net periodic benefit cost	$1.8	$ 1.9	$ 1.5	$ 1.4

	Six Months Ended June 30,			
	Pension Benefits		Other Benefits	
(In millions)	2011	2010	2011	2010
Service cost	$3.5	$3.2	$0.3	$0.2
Interest cost	8.0	7.9	2.1	2.3
Expected return on plan assets	(10.6)	(9.2)	-	(0.2)
Amortization of prior service cost	0.8	0.8	(0.4)	(0.4)
Amortization of transitional obligation	-	-	0.6	0.6
Amortization of actuarial loss	1.9	1.0	0.3	0.3
Net periodic benefit cost	$3.6	$3.7	$2.9	$2.8

Employer Contributions to Qualified Pension Plans

Currently, the Company expects to contribute approximately $35 million to its pension plan trusts for 2011. During the six months ended June 30, 2011, contributions of $30.9 million have been made.

8. Supplemental Cash Flow Information

As of June 30, 2011 and December 31, 2010, the Company has accruals related to utility and nonutility plant purchases totaling approximately $15.4 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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Summarized statement of income information:				
Revenues	$291.2	$267.5	$791.8	$805.7
Operating income (loss)	$(20.1)	$(13.7)	$(37.3)	$0.5
ProLiance's earnings (loss)	$(20.3)	$(13.7)	$(37.7)	$0.6

(In millions)	June 30, 2011	As of December 31, 2010
Summarized balance sheet information:		
Current assets	$282.1	$441.4
Noncurrent assets	$59.9	$59.1
Current liabilities	$171.7	$298.1
Noncurrent liabilities	$0.3	$0.4
Members' equity	$171.2	$208.9
Accumulated other comprehensive income (loss)	$(5.3)	$(10.8)
Noncontrolling interest	$4.1	$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 requested and the FERC approved the separation of 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 June 30, 2011 and December 31, 2010, ProLiance's investment in Liberty approximated $37.1 million and $36.7 million, respectively.

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

Transactions with ProLiance

Purchases from ProLiance for resale and for injections into storage for the three months ended June 30, 2011 and 2010 totaled $81.0 million and $77.8 million, respectively, and for the six months ended June 30, 2011 and 2010, totaled $201.1 and $241.2 million. Amounts owed to ProLiance at June 30, 2011 and December 31, 2010, for those purchases were $27.7 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 June 30, 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 June 30, 2011, parent level guarantees support a maximum of $25 million of ESG's performance contracting commitments and warranty obligations and $27 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 $82 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $56 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 June 30, 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.

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at June 30, 2011, there are 76 open surety bonds supporting future performance. The average face amount of these obligations is $4.2 million, and the largest obligation has a face amount of $30.8 million. The maximum exposure of these obligations is less than these amounts for several factors, including the level of work already completed. At June 30, 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 June 30, 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. Legislative & Environmental Matters

Indiana House Bill 1004
In May 2011, House Bill 1004 was signed into law. This legislation phases in over four years a two percent rate reduction to the Indiana Adjusted Gross Income Tax for corporations. Pursuant to House Bill 1004, the tax rate will be lowered by one-half percent each year beginning on July 1, 2012, to the final rate of six and one-half percent effective July 1, 2015. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the second quarter of 2011, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251
In April 2011, Senate Bill 251 was signed into law. 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.

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 connected 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.

As it relates to the implementation of federal mandates, the law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a base rate increase. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred until the utility's next general rate case. Therefore, for qualifying expenditures, there is reasonable certainty of timely cost recovery ahead of base rate cases. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95
Ohio House Bill 95 was recently signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply to implement a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes recovery or deferral of program costs, such as depreciation, property taxes, and carrying costs. The Company is assessing the impact this legislation may have on its operations.

Clean Air Act
To comply with Indiana's implementation plan of the Clean Air Act of 1990, Clean Air Interstate Regulations (CAIR), and regulation of mercury, SIGECO obtained IURC authority to invest in clean coal technology. Using this authorization, SIGECO has invested approximately $411 million starting in 2001 with the last equipment being placed

into service on January 1, 2010. The pollution control equipment includes Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO_2 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 NO_x emissions where high removal efficiencies are required and fabric filters control particulate matter emissions. The unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order 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.

CAIR is an allowance cap and trade program instituted in 2005 that required reductions from coal-burning power plants for NO_x emissions beginning January 1, 2009 and SO_2 emissions beginning January 1, 2010. 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 revised it per the Court's guidance. SIGECO is in compliance with the current CAIR Phase I annual NO_x reduction requirements in effect on January 1, 2009, and the Phase I annual SO_2 reduction requirements in effect on January 1, 2010.

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.

On July 7, 2011, the EPA finalized its revisions to CAIR, renamed the Cross State Air Pollution Rule.
The rule finalizes the previously proposed 71 percent reduction of SO_2 emissions compared to 2005 national levels and a 52 percent reduction of NOx emissions compared to 2005 national levels. These reductions are to be achieved with initial step reductions beginning in 2012 with final compliance to be achieved in 2014. Based upon an initial review of the final rule, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment and the anticipated allotment of new emission allowances. However, it is possible some minor modifications to the control equipment will be required.

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 CO_2 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.

Potential Pipeline Safety Legislation

There are federal proposals currently pending that would increase the oversight of natural gas pipelines and lead to an investment in the inspection, and where necessary, modernization of pipeline infrastructure. At this time and in the absence of final legislation, compliance costs and other effects associated with increased pipeline safety regulations remain uncertain. However, any future legislative or regulatory actions taken to address pipeline safety could result in both operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Compliance costs and capital investments associated with the Company's Indiana gas utilities would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above. In Ohio, capital investments would likely qualify for timely recovery under House Bill 95.

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 $16.1 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 $9.0 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 June 30, 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 3, 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.

Coal Procurement Procedures

Vectren South recently submitted a request for proposal regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South has reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate order, a sub docket proceeding has been established to review the Company's prospective coal procurement procedures, and the Company expects to submit evidence related to its recent request for proposal and those coal procurement procedures to the IURC in August 2011.

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 2010 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. All flings related to this matter have been made, and an order is expected in 2011.

The settlement currently pending also provides that impacts from energy efficiency programs associated with residential and general service customers be deferred for future recovery. Subject to the approval of the settlement currently before the IURC regarding large customers, the Company expects to propose a rate mechanism to recover residential and general service customer lost margins. This mechanism would be an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011.

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 hearing was held on June 22, 2011. 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.

14. Fair Value Measurements

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

(In millions)	June 30, 2011 Carrying Amount	June 30, 2011 Est. Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Est. Fair Value
Long-term debt	$ 1,719.7	$ 1,853.5	$ 1,715.9	$ 1,841.2
Short-term borrowings & notes payable	144.5	144.5	118.3	118.3
Cash & cash equivalents	14.8	14.8	10.4	10.4

For the balance sheet dates presented in these financial statements, 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.

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 June 30, 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 $11.0 million at June 30, 2011 and $10.9 million at 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.

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 is included in the Infrastructure Services nonutility operating segment. Information related to the Company's business segments is summarized below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2011	2010	2011	2010
Revenues				
Utility Group				
Gas Utility Services	$134.0	$122.9	$490.7	$591.0
Electric Utility Services	159.3	151.0	305.7	295.9
Other Operations	10.9	11.1	21.9	22.2
Eliminations	(10.4)	(10.7)	(20.9)	(21.4)
Total Utility Group	293.8	274.3	797.4	887.7
Nonutility Group				
Infrastructure Services	94.6	65.8	141.8	101.2
Energy Services	39.4	36.9	63.0	61.0
Coal Mining	70.8	50.1	140.2	102.2
Energy Marketing	20.9	15.2	94.9	88.4
Total Nonutility Group	225.7	168.0	439.9	352.8
Eliminations	(43.7)	(39.9)	(78.9)	(97.8)
Consolidated Revenues	$475.8	$402.4	$1,158.4	$1,142.7
Profitability Measure - Net Income (Loss)				
Utility Group				
Gas Utility Services	$2.1	$0.1	$38.3	$39.9
Electric Utility Services	13.6	14.3	22.3	26.7
Other Operations	0.6	1.8	4.3	5.0
Utility Group Net Income	16.3	16.2	64.9	71.6
Nonutility Group Net Income (Loss)				
Infrastructure Services	2.1	2.0	(0.8)	(1.0)
Energy Services	0.7	1.7	(0.7)	1.4
Coal Mining	8.5	1.7	10.1	5.6
Energy Marketing	(11.7)	(8.9)	(12.1)	1.3
Other Businesses	(0.4)	(4.0)	(0.7)	(7.0)
Nonutility Group Net Income (Loss)	(0.8)	(7.5)	(4.2)	0.3
Corporate & Other Group Net Income (Loss)	(0.4)	-	(1.0)	-
Consolidated Net Income	$15.1	$8.7	$59.7	$71.9

16. Impact of Recent Issued Accounting Principles

In June 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance will require entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. Under the two-statement approach, the first statement would include components of net income, which is consistent with the income statement format used today, and the second statement would include components of other comprehensive income (OCI). The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company plans to early adopt this guidance for its annual reporting period ending December 31, 2011. The adoption of this guidance will have no material impacts to the Company's financial statements.

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 565,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 141,000 electric customers and approximately 110,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. The Ohio operations provide energy delivery services to over 312,000 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.

Summary results for the three and six months ended June 30, 2011 and 2010 follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2011	2010	2011	2010
Net income (loss)	$15.1	$8.7	$59.7	$71.9
Attributed to:				
Utility Group	16.3	16.2	64.9	71.6
Nonutility Group	(0.8)	(7.5)	(4.2)	0.3
Corporate & other	(0.4)	-	(1.0)	-
Basic EPS	$0.19	$0.11	$0.73	$0.89
Attributed to:				
Utility Group	0.20	0.20	0.79	0.89
Nonutility Group	(0.01)	(0.09)	(0.05)	-
Corporate & other	-	-	(0.01)	-

Results

For the three months ended June 30, 2011, net income was $15.1 million, or $0.19 per share, compared to a net income of $8.7 million, or $0.11 per share for the three months ended June 30, 2010. For the six months ended June 30, 2011, net income was $59.7 million, or $0.73 per share, compared to net income of $71.9 million, or $0.89 per share for the same period in 2010. The 2010 results were impacted by charges related to legacy investments totaling $4.0 million after tax, or $0.05 per share in the second quarter, and $6.8 million after tax, or $0.08 per share in the year to date period.

Utility Group

In the second quarter of 2011, the Utility Group earned $16.3 million which is comparable to the $16.2 million earned in 2010. Year to date in 2011, utility earnings were $64.9 million compared to $71.6 million in 2010, a decrease of $6.7 million. The year to date decrease is driven primarily by increased operating expenses associated with planned electric generating maintenance activities, warmer cooling weather in the prior year, and the expected first quarter impact of rate design changes implemented in February 2010 in the Ohio service territory. During the second quarter, increased margin from the Vectren South electric rate increase implementation largely offset these impacts.

In the Company’s electric territory, management estimates the margin impact of weather to be approximately $1.7 million favorable and $1.5 million favorable, compared to normal temperatures in the quarter and year to date in 2011, respectively. This compares to 2010, where management estimated a $3.4 million favorable impact on margin compared to normal in the second quarter and $4.2 million year to date.

Nonutility Group

The Nonutility Group’s 2011 second quarter loss was $0.8 million compared to a loss of $7.5 million in 2010. Year to date in 2011, nonutility losses were $4.2 million compared to earnings of $0.3 million in 2010. The changes were driven by improved earnings in Coal Mining operations offset by lower results from ProLiance and legacy charges in 2010 of $4.0 million and $6.8 million in the quarter and year to date periods, respectively.

Dividends

Dividends declared for the three months ended June 30, 2011, were $0.345 per share compared to $0.340 per share for the same period in 2010. Dividends declared for the six months ended June 30, 2011, were $0.690 per share compared to $0.680 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.

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 and six months ended June 30, 2011 and 2010 follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2011	2010	2011	2010
OPERATING REVENUES				
Gas utility	$ 134.0	$ 122.9	$ 490.7	$ 591.0
Electric utility	159.3	151.0	305.7	295.9
Other	0.5	0.4	1.0	0.8
Total operating revenues	293.8	274.3	797.4	887.7
OPERATING EXPENSES				
Cost of gas sold	48.8	41.5	243.9	339.3
Cost of fuel & purchased power	60.3	57.8	119.8	115.8
Other operating	78.2	71.2	165.1	152.8
Depreciation & amortization	47.9	46.8	96.1	93.3
Taxes other than income taxes	11.1	11.6	29.1	33.9
Total operating expenses	246.3	228.9	654.0	735.1
OPERATING INCOME	47.5	45.4	143.4	152.6
OTHER INCOME - NET	2.2	0.8	3.9	3.0
INTEREST EXPENSE	20.4	20.3	40.8	40.6
INCOME BEFORE INCOME TAXES	29.3	25.9	106.5	115.0
INCOME TAXES	13.0	9.7	41.6	43.4
NET INCOME	$ 16.3	$ 16.2	$ 64.9	$ 71.6
CONTRIBUTION TO VECTREN BASIC EPS	$ 0.20	$ 0.20	$ 0.79	$ 0.89

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 June 30,		Six Months Ended June 30,	
(In millions)	2011	2010	2011	2010
Gas utility revenues	$134.0	$122.9	$490.7	$591.0
Cost of gas sold	48.8	41.5	243.9	339.3
Total gas utility margin	$85.2	$81.4	$246.8	$251.7
Margin attributed to:				
Residential & commercial customers	$69.9	$67.9	$209.4	$216.4
Industrial customers	12.0	10.1	29.7	26.3
Other	3.3	3.4	7.7	9.0
Total gas utility margin	$85.2	$81.4	$246.8	$251.7
Sold & transported volumes in MMDth attributed to:				
Residential & commercial customers	11.7	8.9	64.5	63.5
Industrial customers	21.1	19.2	49.9	45.8
Total sold & transported volumes	32.8	28.1	114.4	109.3

Gas utility margins were $85.2 million and $246.8 million for the for the three and six months ended June 30, 2011, and compared to 2010 increased $3.8 in the quarter and decreased $4.9 million year to date. Management estimates a year to date decrease of $3.5 million due to Ohio rate design changes, as described below. Returns generated on investments in bare steel/ cast iron and distribution riser replacement in Ohio increased margins $0.6 million quarter over quarter and $1.4 million year to date. Large customer margin, net of the impacts of regulatory initiatives and tracked costs, increased by $1.7 million in the quarter and $3.1 million year to date due primarily to increased volumes sold, largely from ethanol producers. Margin increased $1.0 million in the quarter and decreased $4.8 million year to date due to lower revenue taxes and operating costs directly recovered in margin.

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 are recovered through the customer service charge. However, 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.

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

Electric utility margin and volumes sold by customer type follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2011	2010	2011	2010
Electric utility revenues	$159.3	$151.0	$305.7	$295.9
Cost of fuel & purchased power	60.3	57.8	119.8	115.8
Total electric utility margin	$99.0	$93.2	$185.9	$180.1
Margin attributed to:				
Residential & commercial customers	$63.0	$59.9	$117.0	$115.2
Industrial customers	25.5	24.4	48.9	46.9
Other customers	1.6	2.3	3.5	4.0
Subtotal: retail	$90.1	$86.6	$169.4	$166.1
Wholesale power & transmission system margin	8.9	6.6	16.5	14.0
Total electric utility margin	$99.0	$93.2	$185.9	$180.1
Electric volumes sold in GWh attributed to:				
Residential & commercial customers	677.9	716.5	1,359.5	1,428.4
Industrial customers	680.9	697.1	1,342.8	1,307.5
Other customers	4.8	5.1	10.7	11.1
Total retail volumes sold	1,363.6	1,418.7	2,713.0	2,747.0

Retail

Electric retail utility margins were $––––90.1 million and $169.4 million for the three and six months ended June 30, 2011, and compared to 2010 increased over the prior year periods by $3.5 million and $3.3 million, respectively. The impact of new base rates increased margin $5.9 million in the quarter and year to date periods. Management estimates the impact of weather, which was warmer than normal but cooler compared to the prior year, to have decreased residential and commercial margin $1.7 million in the second quarter and $2.7 million year to date compared to the prior year periods.

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:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2011	2010	2011	2010
Off-system sales	$2.4	$0.8	$4.4	$3.4
Transmission system sales	6.5	5.8	12.1	10.6
Total wholesale margin	$8.9	$6.6	$16.5	$14.0

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 $6.5 million and $12.1 million for the three and six months ended June 30, 2011, respectively, compared to $5.8 million and $10.6 million in both the three and six months ended June 30, 2010. Increases are primarily due to 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 $100 million, the Company has invested approximately $64.0 million as of June 30, 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.

For the three and six months ended June 30, 2011, margin from off-system sales were $2.4 million and $4.4, respectively, compared to $0.8 million and $3.4 million for the three and six months ended June 30, 2010. The base rate changes implemented in May 2011 require that wholesale margin from off-system sales earned above or below $7.5 million be shared equally with customers. This compares to a $10.5 million sharing threshold established in 2007. Results for the periods presented reflect the impact of that sharing. Off-system sales totaled 327 GWh and 344 GWh during the six months ended June 30, 2011 and 2010, respectively.

Utility Group Operating Expenses

Other Operating
For the three and six months ended June 30, 2011, other operating expenses were $78.2 million and $165.1 million, which reflect increases of $7.0 million and $12.3 million respectively, compared to 2010. These increases result primarily from an $8.2 million increase in the quarter and a $12.1 million year to date increase associated with power supply operating costs, of which $6.2 million and $9.6 million, respectively, are planned outage maintenance.

Depreciation & Amortization
For the three and six months ended June 30, 2011, depreciation expense was $47.9 million and $96.1 million, which represents increases of $1.1 million and $2.8 million, respectively, compared to 2010. These increases reflect utility investments placed into service, which were offset by lower amortizations of certain deferred costs pursuant to the recent electric base rate order.

Taxes Other Than Income Taxes
For the three and six months ended June 30, 2011, taxes other than income taxes were $11.1 million and $29.1 million, respectively, which reflect decreases of $0.5 million for the quarter and $4.8 million year to date. The year to date decrease is primarily attributable to lower Ohio excise and usage taxes associated with that territory's ongoing process of exiting the merchant function, which started in the second quarter of last year. Excise and usage related taxes are offset dollar-for-dollar with lower gas utility revenues.

Utility Group Other Income-Net
Other income-net reflects income of $2.2 million and $3.9 million for the three and six months ended June 30, 2011, compared to $0.8 million and $3.0 million for the same periods in 2010. The increases primarily reflect greater post in service carrying costs on increased distribution replacement program spending.

Utility Group Interest Expense
For the three and six months ended June 30, 2011, interest expense was $20.4 million and $40.8 million, and is generally flat compared to the prior year periods. Interest expense continues to reflect the current low interest rate environment and less reliance by the Utility Group on short-term borrowings. At June 30, 2011 and 2010, the Utility Group had no short-term borrowings outstanding.

Utility Group Income Taxes

In 2011, Utility Group federal and state income taxes were $13.0 million for the quarter and $41.6 million year to date. The increased expense of $3.3 million quarter over quarter reflects increased pre-tax income, the impact of a one time adjustment of $1.4 million, and the amortization of certain income tax related regulatory liabilities associated with the recently concluded electric base rate case. The year to date decrease of $1.8 million primarily reflects lower pre-tax income.

Legislative & Environmental Matters

Indiana House Bill 1004
In May 2011, House Bill 1004 was signed into law. This legislation phases in over four years a two percent rate reduction to the Indiana Adjusted Gross Income Tax for corporations. Pursuant to House Bill 1004, the tax rate will be lowered by one-half percent each year beginning on July 1, 2012, to the final rate of six and one-half percent effective July 1, 2015. Pursuant to FASB guidance, the Company accounted for the effect of the change in tax law on its deferred taxes in the second quarter of 2011, the period of enactment. The impact was not material to results of operations.

Indiana Senate Bill 251
In April 2011, Senate Bill 251 was signed into law. 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.

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 connected 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.

As it relates to the implementation of federal mandates, the law applies to both gas and electric utility operations and provides a framework to recover 80 percent of federally mandated costs through a periodic rate adjustment mechanism outside of a base rate increase. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred until the utility’s next general rate case. Therefore, for qualifying expenditures, there is reasonable certainty of timely cost recovery ahead of base rate cases. The Company is currently evaluating the impact this law may have on its operations, including applicability to expenditures associated with the integrity, safety, and reliable operation of natural gas pipelines and facilities; ash disposal; water regulations; and air pollution, including greenhouse gas emissions, among other federally mandated projects and potential projects.

Ohio House Bill 95
Ohio House Bill 95 was recently signed into law. The law adjusts, among other things, the manner in which gas utilities file for rate changes, including the implementation of base rate changes, alternative rate plans, and automatic rate adjustment mechanisms. Outside of a base rate proceeding, the legislation permits a natural gas company to apply to implement a capital expenditure program for infrastructure expansion, upgrade, or replacement; installation, upgrade, or replacement of information technology systems; or any program necessary to comply with government regulation. Once such application is approved, the legislation authorizes recovery or deferral of program costs, such as depreciation, property taxes, and carrying costs. The Company is assessing the impact this legislation may have on its operations.

Clean Air Act
To comply with Indiana’s implementation plan of the Clean Air Act of 1990, Clean Air Interstate Regulations (CAIR), and regulation of mercury, SIGECO obtained IURC authority to invest in clean coal technology. Using this authorization, SIGECO has invested approximately $411 million starting in 2001 with the last equipment being placed

into service on January 1, 2010. The pollution control equipment includes 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 unamortized portion of the $411 million clean coal technology investment was included in rate base for purposes of determining SIGECO's new electric base rates approved in the latest base rate order recently obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

CAIR is an allowance cap and trade program instituted in 2005 that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010. 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 revised 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.

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.

On July 7, 2011, the EPA finalized its revisions to CAIR, renamed the Cross State Air Pollution Rule.
The rule finalizes the previously proposed 71 percent reduction of SO_2 emissions compared to 2005 national levels and a 52 percent reduction of NOx emissions compared to 2005 national levels. These reductions are to be achieved with initial step reductions beginning in 2012 with final compliance to be achieved in 2014. Based upon an initial review of the final rule, the Company believes that it will be able to meet these requirements with its existing suite of pollution control equipment and the anticipated allotment of new emission allowances. However, it is possible some minor modifications to the control equipment will be required.

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 CO_2 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.

Potential Pipeline Safety Legislation

There are federal proposals currently pending that would increase the oversight of natural gas pipelines and lead to an investment in the inspection, and where necessary, modernization of pipeline infrastructure. At this time and in the absence of final legislation, compliance costs and other effects associated with increased pipeline safety regulations remain uncertain. However, any future legislative or regulatory actions taken to address pipeline safety could result in both operating expenses and capital expenditures associated with the Company’s natural gas distribution businesses. Compliance costs and capital investments associated with the Company’s Indiana gas utilities would likely qualify as federally mandated regulatory requirements under Senate Bill 251 referenced above. In Ohio, capital investments would likely qualify for timely recovery under House Bill 95.

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 $16.1 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 $9.0 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 June 30, 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 3, 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.

Coal Procurement Procedures

Vectren South recently submitted a request for proposal regarding coal purchases for a four year period beginning in 2012. After negotiations with bidders, Vectren South has reached an agreement in principle for multi-year purchases with two suppliers, one of which is Vectren Fuels, Inc. Consistent with the IURC direction in the electric rate order, a sub docket proceeding has been established to review the Company's prospective coal procurement procedures, and the Company expects to submit evidence related to its recent request for proposal and those coal procurement procedures to the IURC in August 2011.

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 2010 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. All flings related to this matter have been made, and an order is expected in 2011.

The settlement currently pending also provides that impacts from energy efficiency programs associated with residential and general service customers be deferred for future recovery. Subject to the approval of the settlement currently before the IURC regarding large customers , the Company expects to propose a rate mechanism to recover residential and general service customer lost margins. This mechanism would be an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011.

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 hearing was held on June 22, 2011. 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. In the three months and six months ended June 30, 2010, VEDO's gas costs were $1.8 million and $84.6 million, respectively, while revenue taxes were $1.8 million and $10.5 million, respectively. In the three and six months ended June 30, 2011, gas costs were $1.7 million and $8.9 million, respectively, while revenue taxes were $1.9 million and $6.7 million, respectively. Therefore, generally there was no change in Gas utility revenues resulting from VEDO's exit of the merchant function in the current quarter, and such revenues decreased approximately $79.5 million year to date.

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 and six months ended June 30, 2011 and 2010 follow:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share amounts)	2011	2010	2011	2010
NET INCOME (LOSS)	$(0.8)	$(7.5)	$(4.2)	$0.3
CONTRIBUTION TO VECTREN BASIC EPS	$(0.01)	$(0.09)	$(0.05)	$-
NET INCOME (LOSS) ATTRIBUTED TO:				
Infrastructure Services	$2.1	$2.0	$(0.8)	$(1.0)
Energy Services	0.7	1.7	(0.7)	1.4
Coal Mining	8.5	1.7	10.1	5.6
Energy Marketing	(11.7)	(8.9)	(12.1)	1.3
Other Businesses	(0.4)	(4.0)	(0.7)	(7.0)

Infrastructure Services

Infrastructure Services provides underground construction and repair to utility infrastructure through Miller Pipeline (Miller) and Minnesota Limited, which was acquired on March 31, 2011. Inclusive of holding company costs, results from Infrastructure's operations for the three and six months ended June 30, 2011 was earnings of $2.1 million and a loss of $0.8 million, respectively. These results were generally flat compared to the prior year periods. The year to date loss is seasonal as the construction activity occurs primarily in the second half of the year. The delayed timing of projects at Miller Pipeline largely offset the $0.5 million of earnings recorded during the second quarter of 2011 related to Minnesota Limited's operations.

Acquisition of Minnesota Limited

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 is headquartered in Big Lake, Minnesota 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.

(In millions)	
Working capital assets	$ 21.5
Working capital liabilities	(6.7)
Net Working Capital	14.8
Property, plant & equipment	34.4
Identifiable intangible assets	19.2
Goodwill	20.2
Net assets acquired	88.6
Debt obligation assumed	(5.2)
Cash paid in acquisition, net of cash acquired	$ 83.4

As of August 4, 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. Since the initial purchase price allocation disclosed on March 31, 2011, minor adjustments to working capital accounts have been made to the opening balance sheet. The final purchase price and the allocation are dependent on final reconciliations of certain working capital items, and final valuation of 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.

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 six months ended June 30, 2011 and the remainder was expensed in 2010. For the period from April 1, 2011 through June 30, 2011, Minnesota Limited contributed approximately $22.0 million and $0.5 million to the Company's revenue and net income, respectively.

The following table presents the Company's unaudited proforma results of operations for the three months ended June 30, 2010 and six months ended June 30, 2011 and 2010 as if the acquisition had occurred on January 1, 2010.

	Three Months Ended June 30,	Six Months Ended June 30,	
(In millions, except per share data)	2010	2011	2010
Nonutility operating revenues	$422.4	$1,158.4	$1,148.6
Net income	$7.8	$59.5	$69.8
Basic earnings per share	$0.10	$0.73	$0.86

Diluted earnings per share	$0.10	$0.73	$0.86

In addition to the incremental revenues and expenses recorded by Minnesota Limited during this period, the proforma financial data for all periods presented contain several adjustments including the following: recording the additional amortization expense from the identifiable intangible assets; adjusting the estimated tax provision of the proforma combined results; and adjusting for the issuance of short-term debt to facilitate the acquisition. The Company prepared the proforma financial information for the combined entities for comparative purposes only, and it 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.

Construction activity for the remainder of 2011 is expected to be strong as utilities and pipelines continue to replace their aging natural gas and oil infrastructure and as the need for shale gas infrastructure becomes more prevalent.

Energy Services

Energy Services provides energy performance contracting and renewable energy services through Energy Systems Group, LLC (ESG). Inclusive of holding company costs, Energy Services' operations contributed earnings of $0.7 million during the second quarter of 2011, compared to earnings of $1.7 million in 2010. Year to date losses were $0.7 million in 2011, compared to earnings of $1.4 million in 2010.

The lower results in 2011 are primarily due to increased operating costs related to ramp up of the sales force and related recruitment costs. At June 30, 2011, backlog was $140 million compared to $118 million at December 31, 2010, and $82 million at June 30, 2010. A significant portion of the backlog should be produced in the next two quarters. The national focus on a comprehensive energy strategy and a continued focus on renewable energy, energy conservation, and sustainability are expected to create favorable conditions for future growth in this area.

Coal Mining

Coal Mining owns mines that produce and sell coal to the Company's utility operations and to third parties through its wholly owned subsidiary Vectren Fuels, Inc. (Vectren Fuels). Coal Mining, inclusive of holding company costs, earned approximately $8.5 million during the quarter ended June 30, 2011, compared to $1.7 million in 2010, an increase of $6.8 million. Year to date, Coal Mining results were $10.1 million compared to earnings of $5.6 million in 2010, an increase of $4.5 million.

Coal Mining revenues were $71 million and $140 million and represent increases of $21 million and $38 million compared to prior year periods, respectively. The increases reflect increased sales to third parties. Second quarter operating results reflect a record earnings contribution driven primarily by the higher sales and record production. In addition, the cost per ton mined also decreased in the quarter and year over year as a result of the lower costs at our Oaktown mine. The anticipated 2011 coal production is approximately 5 million tons, with total sales in 2011 of 5.1 million tons expected. Over 90 percent of those sales have been contracted and priced.

Vectren Fuels is currently in negotiation with a number of customers regarding sales in 2012 and beyond. Vectren Fuels and Vectren South recently reached an agreement in principle whereby existing contracts that had entered into price reopener status have been re-priced. Pursuant to this agreement and other contracts in place, Vectren Fuels expects to supply Vectren South, including its plant jointly owned with ALCOA, approximately 1.5 million tons in 2012. Sales to Vectren South are expected to be at least 2.3 million tons in both 2013 and 2014. The agreements reached in principle will be submitted to the IURC for review as part of a pending proceeding to review Vectren South's coal procurement practices. At this time, including the Vectren South agreement to be reviewed and agreements reached with third parties that are subject to final contract language, approximately 70 percent of Vectren Fuel's planned 2012 production has been subscribed.

Coal Reserves

As of June 30, 2011 management estimates the Company's total Illinois Basin coal reserves to be approximately 135 million tons. Of this amount, approximately 39 million tons are attributable to a mine located at the Company's

Oaktown mining complex that is currently under construction and is expected to open in 2012. However, Vectren Fuels may continue to adjust this timing as it evaluates the impacts of market conditions. The Company estimates approximately $15 million of additional capital is required to complete the mine. Once this mine is in production, Vectren Fuels underground mines are capable of producing about 7.5 million tons of coal per year.

Mine Safety Information
The Company, through its wholly owned subsidiary Vectren Fuels, Inc., owns coal mines and related assets located in Indiana. The Company has retained independent third party contract mining companies to operate its coal mines. Five Star Mining LLC ("Five Star") is the contract mining company at the Prosperity underground mine and Black Panther Mining LLC ("Black Panther") is the contract mining company at the Oaktown underground mines. While in operation, Vigo-Cypress Creek, LLC was the contract mining company at Cypress Creek surface mine. The contract mining companies are the mine "operator", as that term is used in both the Federal Mine Safety and Health Act of 1977 (the "Mine Act") and the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010. All employees at the coal mines are hired, supervised, and paid by the contract mining companies. As the mine operator, the contract mining companies make all regulatory filings required by the MSHA. In most circumstances, however, the cost of fines and penalties assessed by MSHA are contractually passed through from the contract mining company to Vectren Fuels. The process of settling such claims can take years in certain circumstances. During the six months ended June 30, 2011, the Company paid approximately $0.1 million related to assessments issued to the mine operators.

More detailed information about the Company's mines, including safety-related data, can be found at MSHA's website, www.MSHA.gov. Prosperity operates under the MSHA identification number 1202249; the Oaktown mining complex operates under the identification numbers 1202394 and 1202418; and Cypress Creek's identification number is 1202178. Mine safety-related data included on the MSHA website is influenced by the size of the mine, the level of activity at the mine, and the mine inspector's judgment, among other factors. These factors can impact the comparability of information from mine to mine and time period to time period. Given the recent incidents at coal mines of other companies, a significant increase in the frequency and scope of MSHA inspections continues. In addition, both houses of Congress are considering new mine safety legislation. The Company is currently assessing the impact new laws and regulations may have on its investments.

Energy Marketing

Energy Marketing is comprised of the Company's gas marketing operations, energy management services, and retail gas supply operations. Inclusive of holding company costs, results from Energy Marketing for the quarter ended June 30, 2011, were a loss of $11.7 million, compared to a loss of $8.9 million in 2010. For the six months ended June 30, 2011, losses were $12.1 million compared to earnings of $1.3 million in 2010.

Vectren Source
Vectren Source, a wholly owned subsidiary, provides natural gas and other related products and services to customers opting for choice among energy providers. Vectren Source incurred a seasonal loss of approximately $2.5 million in the second quarter of 2011, compared to a loss of $1.9 million in 2010. Year to date, Vectren Source has earned $4.6 million in 2011 compared to $4.4 million in 2010. Seasonal second quarter losses increased over the prior year due primarily to lower per unit gross margins. Vectren Source's customer count at June 30, 2011, was approximately 258,000 customers, compared to 205,000 customers at June 30, 2010. The 2011 customer count reflects nearly 140,000 customers in Vectren Energy Delivery of Ohio's (VEDO) service territory that have either voluntarily opted to choose their natural gas supplier or are supplied natural gas by Vectren Source but remain customers of the regulated utility as part of VEDO's exit from merchant function process. As a result of a supplier choice auction held on January 18, 2011 in VEDO's service territory, Vectren Source increased its customer base by 28,000 in the second quarter of 2011.

ProLiance
ProLiance, a nonutility energy marketing affiliate of Vectren and 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 and 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. Therefore, the Company accounts for its investment in ProLiance using the equity method of accounting. 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.

Vectren Energy Marketing and Services, Inc (EMS), a wholly owned subsidiary, holds the Company's investment in ProLiance. Within the consolidated entity, EMS is responsible for certain financing costs associated with ProLiance and is also responsible for income taxes and allocated corporate expenses related to the Company's portion of ProLiance's results. During the quarter ended June 30, 2011, EMS' results related to the Company's share of ProLiance's results, which include financing costs and income taxes, was a loss of approximately $9.2 million compared to a loss of $7.0 million in 2010. During the six months ended June 30, 2011, results at EMS related to ProLiance was a loss of approximately $16.7 million compared to a loss of $3.1 million in 2010.

The $2.2 million quarter over quarter and $13.6 million year to date increased loss reflects the impact on the market of new natural gas sources from shale and greater transmission capacity, as well as the impacts of reduced industrial demand for natural gas in the Midwest and is consistent with trends experienced dating back to the latter part of 2010. These conditions have resulted in plentiful natural gas supply and lower and less volatile natural gas prices. Historical basis differences between physical and financial markets and summer and winter prices have narrowed. As a result, there have been reduced opportunities to optimize ProLiance's firm transportation and storage capacity. ProLiance has structured optimization activities to remain flexible to maximize potential opportunities if market conditions improve.

ProLiance has approximately $80 million of annual fixed costs related to its transportation and storage contracts, with contracts representing nearly one-third of these fixed costs expiring over the next two and one half years and one-half over the next four and one half years. At June 30, 2011 ProLiance continued to maintain significant sources of liquidity beyond its credit facility which was renewed at a lower level of $130 million given reduced needs with lower gas costs for a one year period on May 18, 2011. At June 30, 2011, ProLiance's balance sheet has nearly $55 million of cash, over $170 million of members' equity, and no long-term debt or working capital debt outstanding. Various profit improvement initiatives are underway, including lowering the cost of pipeline demand costs through ongoing pipeline renegotiations. Given market conditions at the current depressed levels, it is currently anticipated that ProLiance will operate at a loss of $0.15 to $0.25 per share in 2011. Changes in these currently depressed market conditions or other circumstances could cause actual results to be materially above or below this range.

For the three and six months ended June 30, 2011, the amounts recorded to Equity in earnings of unconsolidated affiliates related to ProLiance's operations totaled a pre-tax loss of $12.4 million and $23.0 million, respectively. For the three and six months ended June 30, 2010, the amounts recorded to Equity in earnings (losses) of unconsolidated affiliates related to ProLiance's operations totaled a pretax loss of $8.4 million and income of $0.4 million, respectively.

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 requested and the FERC approved the separation of the North site from the South site. ProLiance's ability to meet the needs of its customers has not been, nor does it expect it to be, impacted. As of June 30, 2011 and December 31, 2010, ProLiance's investment in Liberty approximated $37.1 million and $36.7 million, respectively.

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

Other Businesses

Other nonutility businesses reflect a loss in 2010 due to a $4.0 million after tax charge related to a decline in the fair value of an energy-related investment originally made in 2004 by Haddington Energy Partners, and accounted for by the company using the equity method. The six months ended June 30, 2010 reflect the second quarter loss associated with the Haddington investment and a 2010 first quarter $2.8 million after tax charge related to the reduction in value of a note receivable recorded in 2002 related to a previously exited business.

Haddington Energy Partnerships
The Company has an approximate 40 percent ownership interest in Haddington Energy Partners, LP (Haddington I) and Haddington Energy Partners II, LP (Haddington II). These Haddington ventures have interests in two remaining mid-stream energy related investments. Both Haddington ventures are investment companies accounted for using the equity method of accounting.

In the second quarter of 2010, the Company was notified by Haddington's management that the fair value of its investment in a liquefied natural gas facility (LNG) had declined, and Haddington reflected that decline in its financial statements. The Company recorded its share of the decline in fair value and also impaired a note receivable associated with the LNG investment. In total, the charge was approximately $6.5 million, of which, $6.1 million is reflected in Equity in earnings of unconsolidated affiliates and $0.4 million is reflected in Other-net, for both the three and six months ended June 30, 2010. At June 30, 2011, the Company's remaining $3.4 million investment in the Haddington ventures is related to payments to be received associated with the sale of a compressed air storage facility sold in 2009. The Company has no further commitments to invest in either Haddington I or II.

Impact of Recently Issued Accounting Guidance

Comprehensive Income

In June 2011, the FASB issued new accounting guidance regarding the presentation of comprehensive income within financial statements. The new guidance will require entities to report components of comprehensive income in either (1) a continuous statement of comprehensive income or (2) two separate but consecutive statements. Under the two-statement approach, the first statement would include components of net income, which is consistent with the income statement format used today, and the second statement would include components of other comprehensive income (OCI). The guidance does not change the items that must be reported in OCI. The new guidance is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 and retrospective application is required. The Company plans to early adopt this guidance for its annual reporting period ending December 31, 2011. The adoption of this guidance will have no material impacts to the Company's financial statements.

Financial Condition

Within Vectren's consolidated group, Utility Holdings primarily funds the short-term and long-term financing needs of the Utility Group operations, and Vectren Capital Corp (Vectren Capital) funds short-term and long-term financing needs of the Nonutility Group and corporate operations. Vectren Corporation guarantees Vectren Capital's debt, but does not guarantee Utility Holdings' debt. Vectren Capital's long-term debt, including current maturities, and short-term obligations outstanding at June 30, 2011 approximated $410 million and $145 million, respectively. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt, including current maturities, outstanding at June 30, 2011 approximated $918 million. As of June 30, 2011, Utility Holdings had no short-term borrowings outstanding. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt outstanding at June 30, 2011, was $387 million.

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

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at June 30, 2011, are A-/A3 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. The credit ratings on SIGECO's secured debt are A/A1. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55 percent of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 46 percent of long-term capitalization at both June 30, 2011 and December 31, 2010. Long-term capitalization includes long-term debt, including current maturities and debt subject to tender, as well as common shareholders' equity.

As of June 30, 2011, the Company was in compliance with all debt covenants.

Available Liquidity in Current Credit Conditions

The Company's A-/A3 investment grade credit ratings have allowed it to access the capital markets as needed. Over the last three years, the Company has reduced its reliance on short-term borrowing capacity with the completion of several long-term financing transactions including issuances of long-term debt and the settlement of an equity forward contract. The Company anticipates funding future capital expenditures and dividends through internally generated funds. In addition, available liquidity is expected to be enhanced by the extension of bonus depreciation legislation.

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 closing conditions precedent, the notes will be issued 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 June 30, 2011 Consolidated Balance Sheet to reflect the Company's ability and intent to refinance that portion of the debt on a long-term basis with this issuance.

Consolidated Short-Term Borrowing Arrangements

At June 30, 2011, the Company has $600 million of short-term borrowing capacity, including $350 million for the Utility Group and $250 million for the wholly owned Nonutility Group and corporate operations. No borrowings were outstanding at June 30, 2011 for the Utility Group operations. As reduced by borrowings currently outstanding which includes impacts from the Minnesota Limited acquisition, approximately $105 million was available for the wholly owned Nonutility Group and corporate operations. These facilities are used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis.

Following is certain information regarding these short-term borrowing arrangements.

(In millions)	Utility Group Borrowings 2011	Utility Group Borrowings 2010	Nonutility Group Borrowings 2011	Nonutility Group Borrowings 2010
Six Months Ended June 30				
Balance Outstanding	$-	$-	$144.5	$145.6
Weighted Average Interest Rate	n/a	n/a	1.96 %	0.72 %
Six Months Ended June 30 Average				
Balance Outstanding	$11.6	$0.6	$89.1	$166.6
Weighted Average Interest Rate	0.39 %	0.25 %	2.02 %	0.64 %
Maximum Month End Balance Outstanding	$42.5	$-	$144.5	$174.6

(In millions)	Utility Group Borrowings 2011	Utility Group Borrowings 2010	Nonutility Group Borrowings 2011	Nonutility Group Borrowings 2010
Quarterly Average - June 30				
Balance Outstanding	$-	$-	$128.1	$155.3
Weighted Average Interest Rate	n/a	n/a	2.01 %	0.67 %
Maximum Month End Balance Outstanding	$-	$-	$144.5	$149.4

ProLiance Short-Term Borrowing Arrangements

ProLiance, a nonutility energy marketing affiliate of the Company, has separate borrowing capacity available through a syndicated credit facility. This facility was renewed on May 18, 2011 at a $130 million capacity level as adjusted for letters of credit and current inventory and receivable balances. This new one year credit facility reflects the impact of lower gas prices and resulting lower working capital need. As of June 30, 2011, no borrowings were outstanding and ProLiance had $53 million of cash on hand to meet its liquidity requirements. The facility is not guaranteed by Vectren or Citizens.

New Share Issues

The Company may periodically issue new common shares to satisfy the dividend reinvestment plan, stock option plan and other employee benefit plan requirements. New issuances added additional liquidity of $3.6 million and $3.1 million in the six months ended June 30, 2011 and 2010, respectively. Throughout 2011, new issuances required to meet these various plan requirements are estimated to be approximately $6 million.

Vectren Capital Financing

In December 2010, the Company, through Vectren Capital, issued $125 million of senior unsecured notes. The proceeds were used to refinance maturing long-term debt, to permanently finance coal mine investments, and to provide sufficient liquidity for the growth in the Nonutility Group, such as the Minnesota Limited acquisition. The Company currently has no near term plans for additional permanent financing.

Potential Uses of Liquidity

Pension & Postretirement Funding Obligations

During the six months ended June 30, 2011, $30.9 million in contributions to qualified pension plans were made. The Company anticipates $4.1 million of additional funding in 2011. Of the $35 million of anticipated funding in 2011, $25 million is made available from bonus depreciation opportunities. Management currently estimates contributing $10 million to qualified pension plans in 2012. Contributions in 2012 and beyond are dependent on a variety of factors, including the Company's progress toward attaining its long-term goal of being fully funded related to the plans' accrued benefit obligations and the available sources of cash to fund such additional contributions.

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 June 30, 2011, parent level guarantees support a maximum of $25 million of ESG's performance contracting commitments and warranty obligations and $27 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 $82 million of other guarantees outstanding supporting other consolidated subsidiary operations, of which $56 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 June 30, 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.

Performance Guarantees & Product Warranties

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

Specific to ESG, in its role as a general contractor in the performance contracting industry, at June 30, 2011, there are 76 open surety bonds supporting future performance. The average face amount of these bonds is $4.2 million, and the largest obligation has a face amount of $30.8 million. The maximum exposure of these obligations is less than these amounts for several factors, including the level of work already completed. At June 30, 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.

Other Letters of Credit

As of June 30, 2011, Utility Holdings has letters of credit outstanding in support of two SIGECO tax exempt adjustable rate first mortgage bonds totaling $41.7 million. In the unlikely event the letters of credit were called, the Company could settle with the financial institutions supporting these letters of credit with general assets or by drawing from its credit facility that expires in September of 2013. Due to the long-term nature of the credit agreement, such debt is classified as long-term at June 30, 2011.

Planned Capital Expenditures & Investments

Utility capital expenditures are estimated at $125 million for the remainder of 2011. Nonutility capital expenditures and investments are estimated at $50 million for the remainder of 2011.

Comparison of Historical Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $269.6 million and $258.7 million for the six months ended June 30, 2011 and 2010, respectively. The $10.9 million increase in operating cash flow in 2011 compared to 2010 is primarily due to an increase in deferred taxes caused by the continued impacts of bonus depreciation.

Financing Cash Flow

Net cash flow required for financing activities was $29.4 million during the six months ended June 30, 2011 and reflects the payment of dividends and some increased nonutility borrowings related to the acquisition of Minnesota Limited. This compares to $121.5 million of cash required for financing activities in the prior year period when a greater level of short-term borrowings were repaid.

Investing Cash Flow

Cash flow required for investing activities was $235.8 million and $132.3 million during the six months ended June 30, 2011 and 2010, respectively. The increase in cash required for investing activity reflects the Nonutility Group infrastructure business acquisition more fully described in Note 5 to the consolidated financial statements and some increase in capital expenditures associated with planned outages in the Utility Group and additional investment in equipment for the infrastructure services business in the Nonutility Group.

Forward-Looking Information

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

Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unusual maintenance or repairs; unanticipated changes to fossil fuel costs; unanticipated changes to gas transportation and storage costs, or availability due to higher demand, shortages, transportation problems or other developments; environmental or pipeline incidents; transmission or distribution incidents; unanticipated changes to electric energy supply costs, or availability due to demand, shortages, transmission problems or other developments; or electric transmission or gas pipeline system constraints.

- Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornados, terrorist acts or other similar occurrences could adversely affect Vectren's facilities, operations, financial condition and results of operations.
- Increased competition in the energy industry, including the effects of industry restructuring and unbundling.
- Regulatory factors such as unanticipated changes in rate-setting policies or procedures, recovery of investments and costs made under traditional regulation, and the frequency and timing of rate increases.
- Financial, regulatory or accounting principles or policies imposed by the Financial Accounting Standards Board; the Securities and Exchange Commission; the Federal Energy Regulatory Commission; state public utility commissions; state entities which regulate electric and natural gas transmission and distribution, natural gas gathering and processing, electric power supply; and similar entities with regulatory oversight.
- Economic conditions including the effects of inflation rates, commodity prices, and monetary fluctuations.
- Economic conditions surrounding the current economic uncertainty, including significantly lower levels of economic activity; uncertainty regarding energy prices and the capital and commodity markets; volatile changes in the demand for natural gas, electricity, coal, and other nonutility products and services; impacts on both gas and

electric large customers; lower residential and commercial customer counts; higher operating expenses; and further reductions in the value of certain nonutility real estate and other legacy investments.

- Volatile natural gas and coal commodity prices and the potential impact on customer consumption, uncollectible accounts expense, unaccounted for gas and interest expense.
- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, interest rate, and warranty risks.

- Direct or indirect effects on the Company's business, financial condition, liquidity and results of operations resulting from changes in credit ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- The performance of projects undertaken by the Company's nonutility businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, the Company's infrastructure, energy services, coal mining, and energy marketing strategies.
- Factors affecting coal mining operations including MSHA guidelines and interpretations of those guidelines, as well as additional mine regulations and more frequent and broader inspections that could result from the recent mining incidents at coal mines of other companies; geologic, equipment, and operational risks; the ability to execute and negotiate new sales contracts and resolve contract interpretations; volatile coal market prices and demand; supplier and contract miner performance; the availability of key equipment, contract miners and commodities; availability of transportation; and the ability to access/replace coal reserves.
    - Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Legal and regulatory delays and other obstacles associated with mergers, acquisitions and investments in joint ventures.
- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

These risks are not significantly different from the information set forth in Item 7A Quantitative and Qualitative Disclosures About Market Risk included in the Vectren 2010 Form 10-K and is therefore not presented herein.

ITEM 4. CONTROLS AND PROCEDURES

Changes in Internal Controls over Financial Reporting

During the quarter ended June 30, 2011, there have been no changes to the Company's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of June 30, 2011, the Company conducted an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of June 30, 2011, to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is:

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

PART II

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

Investors should consider carefully factors that may impact the Company’s operating results and financial condition, causing them to be materially adversely affected. The Company’s risk factors have not materially changed from the information set forth in Item 1A Risk Factors included in the Vectren 2010 Form 10-K and are therefore not presented herein.

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

Periodically, the Company purchases shares from the open market to satisfy share requirements associated with the Company’s share-based compensation plans. The following chart contains information regarding open market purchases made by the Company to satisfy share-based compensation requirements during the quarter ended June 30, 2011.

Period	Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares That May Be Purchased Under These Plans
April 1-30	-	$ -	-	-
May 1-31	29,800	28.20	-	-
June 1-30	-	-	-	-

ITEM 5. OTHER INFORMATION

Corporate Code of Conduct

The Company's Corporate Governance Guidelines, its charters for each of its Audit, Compensation and Benefits and Nominating and Corporate Governance Committees, its Corporate Code of Conduct that covers the Company's officers and employees, and its Board Code of Ethics & Code of Conduct that covers the Company's directors are available in the Corporate Governance section of the Company's website, www.vectren.com. The Corporate Code of Conduct (titled "Corp Code of Conduct") contains specific codes of ethics pertaining to executive officers. A separate code of conduct (titled "Board Code of Ethics & Code of Conduct") contains specific codes of ethics pertaining to the Board of Directors. A copy will be mailed upon request to Investor Relations, Attention: Robert L. Goocher, One Vectren Square, Evansville, Indiana 47708. The Company intends to disclose any amendments to the Corporate Code of Conduct/Board Code of Ethics & Code of Conduct or waivers of the Corporate Code of Conduct/ on behalf of the Company's directors or officers including, but not limited to, the principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions on the Company's website at the internet address set forth above promptly following the date of such amendment or waiver and such information will also be available by mail upon request to the address listed above.

ITEM 6. EXHIBITS

Exhibits and Certifications

31.1 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Executive Officer

31.2 Certification Pursuant To Section 302 of The Sarbanes-Oxley Act Of 2002- Chief Financial Officer

32 Certification Pursuant To Section 906 of The Sarbanes-Oxley Act Of 2002

101 Interactive Data File.

101.INS* XBRL Instance Document

101.SCH* XBRL Taxonomy Extension Schema

101.CAL* XBRL Taxonomy Extension Calculation Linkbase

101.DEF* XBRL Taxonomy Extension Definition Linkbase

101.LAB* XBRL Taxonomy Extension Labels Linkbase

101.PRE* XBRL Taxonomy Extension Presentation Linkbase

* Users of the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q are advised in accordance with Rule 406T of Regulation S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed."

SIGNATURES

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

VECTREN CORPORATION
Registrant

August 4, 2011

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

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