VECTREN UTILITY HOLDINGS INC
Form 10-K
March 02, 2012

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2011

OR

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

For the transition period from ___________________ to _________________________

Commission file number: 1-16739

VECTREN UTILITY HOLDINGS, INC.

(Exact name of registrant as specified in its charter)

INDIANA	35-2104850
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
One Vectren Square	47708
(Address of principal executive offices)	(Zip Code)

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Vectren Utility 6.10% SR NTS 12/1/2035	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common – Without Par	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
*Yes ý No
*Utility Holdings is a majority owned subsidiary of a well-known seasoned issuer, and well-known seasoned issuer status depends in part on the type of security being registered by the majority-owned subsidiary.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No ý

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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   Accelerated filer

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2011, was zero. All shares outstanding of the Registrant’s common stock were held by Vectren Corporation.

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

Common Stock - Without Par Value	10	February 29, 2012
Class	Number of Shares	Date

Omission of Information by Certain Wholly Owned Subsidiaries

The Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

Definitions

AFUDC: allowance for funds used during construction	MCF / BCF: thousands / billions of cubic feet
ASC: Accounting Standards Codification	MDth / MMDth: thousands / millions of dekatherms
BTU / MMBTU: British thermal units / millions of BTU	MISO: Midwest Independent System Operator
DOT: Department of Transportation	MW: megawatts
EPA: Environmental Protection Agency	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	NERC: North American Electric Reliability Corporation
FERC: Federal Energy Regulatory Commission	OCC: Ohio Office of the Consumer Counselor
IDEM: Indiana Department of Environmental Management	OUCC: Indiana Office of the Utility Consumer Counselor
IRC: Internal Revenue Code	PUCO: Public Utilities Commission of Ohio
IURC: Indiana Utility Regulatory Commission	Throughput: combined gas sales and gas transportation volumes
Kv: Kilovolt	

Access to Information

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

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

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(A) – Omitted or amended as the Registrant is a wholly owned subsidiary of Vectren Corporation and meets the conditions set forth in General Instructions (I)(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format contemplated thereby.

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PART I

ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (the Company or Utility Holdings), an Indiana corporation, was formed on March 31, 2000 to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO or Vectren Ohio). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 563,000– 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. VEDO provides energy delivery services to over 310,000 natural gas customers located near Dayton in west central Ohio.

Narrative Description of the Business

The Company has regulated operations and other operations that provide information technology and other support services to those regulated operations. The Company segregates its regulated operations into a Gas Utility Services operating segment and an Electric Utility Services operating segment. The Gas Utility Services segment includes the operations of Indiana Gas, VEDO, and SIGECO's natural gas distribution business and provides natural gas distribution and transportation services to nearly two-thirds of Indiana and to west central Ohio. The Electric Utility Services segment includes the operations of SIGECO's electric transmission and distribution services, 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.

At December 31, 2011, the Company had $4.0 billion in total assets, with $2.1 billion (53 percent) attributed to Gas Utility Services, $1.7 billion (42 percent) attributed to Electric Utility Services, and $0.2 billion (5 percent) attributed to Other Operations. Net income for the year ended December 31, 2011, was $122.9 million, with $52.5 million attributed to Gas Utility Services, $65.0 million attributed to Electric Utility Services, and $5.4 million attributed to Other Operations. Net income for the year ended December 31, 2010, was $123.9 million. For further information regarding the activities and assets of operating segments, refer to Note 13 in the Company's consolidated financial statements included under "Item 8 Financial Statements and Supplementary Data."

Following is a more detailed description of the Gas Utility Services and Electric Utility Services operating segments. The Company's Other Operations are not significant.

Gas Utility Services

At December 31, 2011, the Company supplied natural gas service to approximately 993,300 Indiana and Ohio customers, including 908,100 residential, 83,600 commercial, and 1,600 industrial and other contract customers. Average gas utility customers served were approximately 983,700 in 2011, 982,100 in 2010, and 981,300 in 2009.

The Company’s service area contains diversified manufacturing and agriculture-related enterprises. The principal industries served include automotive assembly, parts and accessories, feed, flour and grain processing, metal castings, aluminum products, polycarbonate resin (Lexan®) and plastic products, gypsum products, electrical equipment, metal specialties, glass, steel finishing, pharmaceutical and nutritional products, gasoline and oil products, ethanol, and coal mining. The largest Indiana communities served are Evansville, Bloomington, Terre Haute, suburban areas surrounding Indianapolis and Indiana counties near Louisville, Kentucky. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

The Company receives gas revenues by selling gas directly to customers at approved rates or by transporting gas through its pipelines at approved rates to customers that have purchased gas directly from other producers, brokers, or marketers. Total throughput was 196.9 MMDth for the year ended December 31, 2011. Gas sold and transported to residential and commercial customers was 99.9 MMDth representing 51 percent of throughput. Gas transported or sold to industrial and other contract customers was 97.0 MMDth representing 49 percent of throughput. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

For the year ended December 31, 2011, gas utility revenues were approximately $819.1 million, of which residential customers accounted for 67 percent and commercial 24 percent. Industrial and other contract customers account for only 9 percent of revenues due to the high number of transportation customers in that customer class.

Availability of Natural Gas

The volume of gas sold is seasonal and affected by variations in weather conditions. To mitigate seasonal demand, the Company's Indiana gas utilities have storage capacity at seven active underground gas storage fields and six liquefied petroleum air-gas manufacturing plants. Periodically, purchased natural gas is injected into storage. The injected gas is then available to supplement contracted and manufactured volumes during periods of peak requirements. The volumes of gas per day that can be delivered during peak demand periods for each utility are located in "Item 2 Properties."

Natural Gas Purchasing Activity in Indiana

The Indiana utilities also contract with a wholly-owned subsidiary of ProLiance Holdings, LLC (ProLiance), to ensure availability of gas. ProLiance is an unconsolidated, nonutility, energy marketing affiliate of Vectren and Citizens Energy Group (Citizens). (See the discussion of Energy Marketing in Note 5 in the Company's Consolidated Financial Statements included in "Item 8 Financial Statements and Supplementary Data" regarding transactions with ProLiance). The Company also prepays ProLiance for natural gas delivery services during the seven months prior to the peak heating season in lieu of maintaining gas storage. Vectren received regulatory approval on April 25, 2006, from the IURC for ProLiance to continue to provide natural gas supply services to the Company's Indiana utilities through March 2011. On March 17, 2011, an order was received from the IURC providing for ProLiance's continued provision of gas supply services to the Company's Indiana utilities and Citizens Gas through March 2016.

Natural Gas Purchasing Activity in Ohio

On April 30, 2008, the PUCO issued an order adopting a stipulation involving the Company, the OCC, and other interveners. The order approved the first two phases of a three phase plan to exit the merchant function in the Company's Ohio service territory. The Company used a third party provider for VEDO's gas supply and portfolio services through September 30, 2008.

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. During the initial phase, wholesale suppliers that were winning bidders in a PUCO approved auction provided the gas commodity to VEDO for resale to its residential and general service customers at auction-determined standard pricing. This standard pricing was comprised of the monthly NYMEX settlement price plus a fixed adder. On October 1, 2008, the Company transferred its natural gas inventory at book value to the winning bidders, receiving proceeds of approximately $107 million, and began purchasing natural gas from those suppliers (one of which was Vectren Source, see the discussion of Vectren Source in Note 5 of the Company's Consolidated Financial Statements included in "Item 8 Financial Statements and Supplementary Data"). This method of purchasing gas 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 commenced on April 1, 2011. The results of that auction were approved by the PUCO on January 19, 2011. Vectren Source was also a successful bidder in both auctions winning one tranche of customers in the first auction and two tranches of customers in the second auction. Each tranche of customers equates to approximately 28,000 customers. As per the terms of the plan approved by the PUCO, because no application for a full exit of the merchant function was neither sought nor approved by April 1, 2011, VEDO conducted a third retail auction on January 31, 2012 to address the 12-month term beginning April 1, 2012. The results of that auction were approved by the PUCO on February 1, 2012. Consistent with current practice, customers continue to receive a single bill for the commodity as well as the delivery component of natural gas service from VEDO.

In the last phase, which was not approved in the April 2008 order, it is contemplated that all of the Company's Ohio residential and general service customers will choose their commodity supplier from state-certified Competitive Retail Natural Gas Suppliers in a competitive market.

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.

Total Natural Gas Purchased Volumes
In 2011, Utility Holdings purchased 71.2 MDth volumes of gas at an average cost of $5.30 per Dth, of which approximately 97 percent was purchased from ProLiance, 1 percent was purchased from Vectren Source, and 2 percent was purchased from third party providers. The average cost of gas per Dth purchased for the previous four years was $5.99 in 2010, $5.97 in 2009, $9.61 in 2008, and $8.14 in 2007.

Electric Utility Services

At December 31, 2011, the Company supplied electric service to approximately 141,600 Indiana customers, including approximately 123,200 residential, 18,300 commercial, and 100 industrial and other customers. Average electric utility customers served were approximately 141,400 in 2011, 141,300 in 2010, and 140,900 in 2009.

The principal industries served include polycarbonate resin (Lexan®) and plastic products, aluminum smelting and recycling, aluminum sheet products, automotive assembly, steel finishing, pharmaceutical and nutritional products, automotive glass, gasoline and oil products, ethanol, and coal mining.

Revenues

For the year ended December 31, 2011, retail electricity sales totaled 5,594.8 GWh, resulting in revenues of approximately $593.4 million. Residential customers accounted for 36 percent of 2011 revenues; commercial 27 percent; industrial 36 percent, and other 1 percent. In addition, in 2011 the Company sold 586.7 GWh through wholesale activities principally to the MISO. Wholesale revenues, including transmission-related revenue, totaled $42.5 million in 2011.

System Load

Total load for each of the years 2007 through 2011 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	7/21/2011	8/4/2010	6/22/2009	7/21/2008	8/8/2007
Total load at peak (1)	1,220	1,275	1,143	1,167	1,341
Generating capability	1,298	1,298	1,295	1,295	1,295
Firm purchase supply	136	136	136	135	130
Interruptible contracts & direct load control	60	62	62	62	62
Total power supply capacity	1,494	1,496	1,493	1,492	1,487
Reserve margin at peak	22%	17%	31%	28%	11%

(1) The total load at peak is increased 25 MW in 2007 from the total load actually experienced. The additional 25 MW represents load that would have been incurred if the Summer Cycler program had not been activated. The 25 MW is also included in the interruptible contract portion of the Company's total power supply capacity in that year. During the time of peak in 2008-2011 the Summer Cycler program was not activated.

The winter peak load for the 2010-2011 season of approximately 943 MW occurred on December 14, 2010. The prior winter peak load for the 2009-2010 season was approximately 916 MW, occurring on January 8, 2010.

Generating Capability

Installed generating capacity as of December 31, 2011, was rated at 1,298 MW. Coal-fired generating units provide 1,000 MW of capacity, natural gas or oil-fired turbines used for peaking or emergency conditions provide 295 MW, and in 2009 SIGECO purchased a landfill gas electric generation project which provides 3 MW. Electric generation for 2011 was fueled by coal (97 percent) and natural gas (3 percent). Oil was used only for testing of gas/oil-fired peaking units. The Company generated approximately 4,631 GWh in 2011. Further information about the Company's owned generation is included in "Item 2 Properties."

There are substantial coal reserves in the southern Indiana area, and coal for coal-fired generating stations has been supplied from operators of nearby coal mines, including coal mines in Indiana owned by Vectren Fuels, Inc. (Vectren Fuels), a wholly owned subsidiary of Vectren. Approximately 2.3 million tons were purchased for generating electricity during 2011, of which approximately 90 percent was supplied by Vectren Fuels from its mines. This compares to 2.2 million tons and 2.8 million tons purchased in 2010 and 2009, respectively. The utility's coal inventory was approximately 1 million tons at December 31, 2011 and 2010.

Coal Purchases
The average cost of coal per ton purchased for the last five years was $75.04 in 2011, $70.47 in 2010, $64.28 in 2009, $42.76 in 2008, and $40.86 in 2007. Effective January 1, 2009, SIGECO began purchasing coal from Vectren Fuels under new coal purchase agreements. The term of these coal purchase agreements continues to December 31, 2015, with prices specified originally ranging from two to four years. The prices in these contracts were at or below market prices for Illinois Basin coal at the time of execution and were subject to a bidding process with third parties. The IURC has found that costs incurred under these contracts are reasonable. For contracts with price reopeners, amendments were finalized in 2011 for coal deliveries beginning in 2012 at lower prices.

The Company received an order on January 25, 2012 to allow for the lower prices that are set to begin late in 2012 and beyond to be reflected in customer bills beginning in early 2012. Because the cost of coal expensed in 2012 will be lower than amounts paid under existing contracts and included in the carrying amount of inventory at December 31, 2011, the IURC authorized deferral of the difference between costs paid under these contracts and that charged to customers for future recovery over a six year period beginning in 2014. See Rate and Regulatory Matters in Item 7 regarding coal procurement procedures and electric fuel cost reductions.

Firm Purchase Supply

The Company has a 1.5 percent interest in the Ohio Valley Electric Corporation (OVEC). OVEC is owned by several electric utility companies, including SIGECO, and supplies power requirements to the United States Department of Energy's (DOE) uranium enrichment plant near Portsmouth, Ohio. The participating companies can receive from OVEC, and are obligated to pay for, any available power in excess of the DOE contract demand. At the present time, the DOE contract demand is essentially zero. The Company's 1.5 percent interest in OVEC makes available approximately 30 MW of capacity. The Company purchased approximately 197 GWh from OVEC in 2011.

The Company executed a capacity contract with Benton County Wind Farm, LLC in April 2008 to purchase as much as 30 MW from a wind farm located in Benton County, Indiana, with the approval of the IURC. The contract expires in 2029. In 2011, the Company purchased approximately 80 GWh under this contract.

In−−−− December 2009, the Company executed a 20 year power purchase agreement with Fowler Ridge II Wind Farm, LLC to purchase as much as 50 MW of energy from a wind farm located in Benton and Tippecanoe Counties in Indiana, with the approval of the IURC. The Company purchased 129 GWh under this contract in 2011.

The Company had a capacity contract with Duke Energy Marketing America, LLC to purchase as much as 100 MW at any time from a power plant located in Vermillion County, Indiana. The contract expired on December 31, 2009 and was not renewed.

Other Power Purchases

The Company occasionally enters into short-term purchased power agreements with various suppliers. During 2011, total purchases under these contracts totaled 67 GWh. In addition, the Company also purchases power from the MISO to supplement its generation and firm purchase supply. Volumes purchased from the MISO in 2011 totaled 1,230 GWh.

Midwest Independent System Operator (MISO) Capacity Purchase

In May 2008, the Company executed a MISO capacity purchase from Sempra Energy Trading, LLC to purchase 100 MW of name plate capacity from its generating facility in Dearborn, Michigan. The term of the contract began January 1, 2010 and continues through December 31, 2012.

Interconnections

The Company has interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc., Big Rivers Electric Corporation, and the City of Jasper, Indiana, providing the ability to simultaneously interchange approximately 655 MW. This interchange capability has been impacted in recent years as a result of ongoing initiatives to improve the transmission grid throughout the Midwest. As an example, once completed, a 345 kV Vectren transmission project that is currently in process will result in the ability to simultaneously interchange an additional 100 MW. The Company, as a member of the MISO, has turned over operational control of the interchange facilities and its own transmission assets, like many other Midwestern electric utilities, to MISO.

Competition

The utility industry has undergone structural change for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. Currently, several states have passed legislation allowing electricity customers to choose their electricity supplier in a competitive electricity market and several other states have considered such legislation. At the present time, Indiana has not adopted such legislation. Ohio regulation allows gas customers to choose their commodity supplier. The Company implemented a choice program for its gas customers in Ohio in January 2003. At December 31, 2011, approximately 129,000 customers in Vectren’s Ohio service territory have opted to purchase natural gas from a supplier other than VEDO. In addition, VEDO’s service territory continues transition toward a choice model for all gas customers. Margin earned for transporting natural gas to those customers, who have purchased natural gas from another supplier, are generally the same as those earned by selling gas under Ohio tariffs. Indiana has not adopted any regulation requiring gas choice; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier.

Regulatory and Environmental Matters

See "Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition" regarding the Company's regulatory environment and environmental matters.

Personnel

As of December 31, 2011, the Company and its consolidated subsidiaries had approximately 1,600 employees, of which 700 are subject to collective bargaining arrangements.

In December 2011, the Company reached a three year labor agreement, ending December 1, 2014, with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441.

In June 2010, the Company reached a three year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 30, 2013.

In April 2010, the Company reached a three year agreement with Local 175 of the Utility Workers Union of America. The labor agreement was retroactively effective to November 1, 2009 and ends October 31, 2012.

In September 2009, the Company reached a three year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 23, 2012.

ITEM 1A. RISK FACTORS

Investors should consider carefully the following factors that could cause the Company's operating results and financial condition to be materially adversely affected. New risks may emerge at any time, and the Company cannot predict those risks or estimate the extent to which they may affect the Company's businesses or financial performance.

Utility Holdings is a holding company and its assets consist primarily of investments in its subsidiaries.

The ability of Utility Holdings to receive dividends and repay indebtedness depends on the earnings, financial condition, capital requirements and cash flow of its subsidiaries, SIGECO, Indiana Gas, and VEDO and the distribution or other payment of earnings from those entities to Utility Holdings. Should the earnings, financial condition, capital requirements or cash flow of, or legal requirements applicable to them restrict their ability to pay dividends or make other payments to Utility Holdings, its ability to pay dividends to its parent could be limited. Utility Holdings' results of operations, future growth, and earnings and dividend goals also will depend on the performance of its subsidiaries. Additionally, certain of the Company's lending arrangements contain restrictive covenants, including the maintenance of a total debt to total capitalization ratio.

Deterioration in general economic conditions may have adverse impacts.

Economic conditions may have some negative impact on both gas and electric large customers and wholesale power sales. This impact may include volatility and unpredictability in the demand for natural gas and electricity, tempered growth strategies, significant conservation measures, and perhaps plant closures or bankruptcies. Economic conditions may also cause reductions in residential and commercial customer counts and lower revenues. It is also possible that an uncertain economy could affect costs including pension costs, interest costs, and uncollectible accounts expense. The economic conditions may have some negative impact on utility industry spending for construction projects and demand for natural gas.

Financial market volatility could have adverse impacts.

The capital and credit markets may experience volatility and disruption. If market disruption and volatility occurs, there can be no assurance that the Company will not experience adverse effects, which may be material. These effects may include, but are not limited to, difficulties in accessing the short and long-term debt capital markets and the commercial paper market, increased borrowing costs associated with current short-term debt obligations, higher interest rates in future financings, and a smaller potential pool of investors and funding sources. Finally, there is no assurance the Company will have access to the equity capital markets to obtain financing when necessary or desirable.

A downgrade (or negative outlook) in or withdrawal of Utility Holdings' credit ratings could negatively affect its ability to access capital and its cost.

The following table shows the current ratings assigned to certain outstanding debt by Moody's and Standard & Poor's:

	Current Rating	
	Moody's	Standard & Poor's
Utility Holdings and Indiana Gas senior unsecured debt	A3	A-
Utility Holdings commercial paper program	P-2	A-2
SIGECO's senior secured debt	A1	A

The current outlook of both Standard and Poor's and Moody's is stable and both categorize the ratings of the above securities as investment grade. 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.

If the rating agencies downgrade the Company's credit ratings, particularly below investment grade, or initiate negative outlooks thereon, or withdraw Utility Holdings' ratings or, in each case, the ratings of its subsidiaries, it may significantly limit Utility Holdings' access to the debt capital markets and the commercial paper market, and the Company's borrowing costs would increase. In addition, Utility Holdings would likely be required to pay a higher interest rate in future financings, and its potential pool of investors and funding sources would likely decrease. Finally, there is no assurance that the Company will have access to the equity capital markets to obtain financing when necessary or desirable.

Utility Holdings' gas and electric utility sales are concentrated in the Midwest.

The operations of the Company's regulated utilities are concentrated in central and southern Indiana and west central Ohio and are therefore impacted by changes in the Midwest economy in general and changes in particular industries concentrated in the Midwest. These industries include automotive assembly, parts and accessories; feed, flour and grain processing; metal castings; aluminum products; polycarbonate resin (Lexan®) and plastic products; gypsum products; electrical equipment, metal specialties, glass, steel finishing, pharmaceutical and nutritional products; gasoline and oil products; ethanol and coal mining.

Utility Holdings operates in an increasingly competitive industry, which may affect its future earnings.

The utility industry has been undergoing structural change for several years, resulting in increasing competitive pressure faced by electric and gas utility companies. Increased competition may create greater risks to the stability of the Company's earnings generally and may in the future reduce its earnings from retail electric and gas sales. Currently, several states, including Ohio, have passed legislation that allows customers to choose their electricity supplier in a competitive market. Indiana has not enacted such legislation. Ohio regulation also provides for choice of commodity providers for all gas customers. In 2003, the Company implemented this choice for its gas customers in Ohio and is currently in the second of the three phase process to exit the merchant function in its Ohio service territory. The state of Indiana has not adopted any regulation requiring gas choice in the Company's Indiana service territories; however, the Company operates under approved tariffs permitting certain industrial and commercial large volume customers to choose their commodity supplier. The Company cannot provide any assurance that increased competition or other changes in legislation, regulation or policies will not have a material adverse effect on its business, financial condition or results of operations.

A significant portion of Utility Holdings' electric utility sales are space heating and cooling. Accordingly, its operating results may fluctuate with variability of weather.

Utility Holdings' electric utility sales are sensitive to variations in weather conditions. The Company forecasts utility sales on the basis of normal weather. Since the Company does not have a weather-normalization mechanism for its electric operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in the Company's Indiana territories has been significantly mitigated through the implementation in 2005 of a normal temperature adjustment mechanism. Additionally, the implementation of a straight fixed variable rate design in a January 2009 PUCO order mitigates most weather risk related to Ohio residential gas sales.

Utility Holdings' businesses are exposed to increasing regulation, including environmental and pipeline safety regulation.

Utility Holdings' businesses are subject to regulation by federal, state, and local regulatory authorities and are exposed to public policy decisions that may negatively impact the Company's earnings. In particular, Utility Holdings is subject to regulation by the FERC, the NERC, the EPA, the IURC, the PUCO, and the DOT. These authorities regulate many aspects of its transmission and distribution operations, including construction and maintenance of facilities, operations, and safety, and its gas marketing operations involving title passage, reliability standards, and future adequacy. In addition, these regulatory agencies approve its utility-related debt and equity issuances, regulate the rates that the Company can charge customers, the rate of return that the Company is authorized to earn, and its ability to timely recover gas and fuel costs. Further, there are consumer advocates and other parties which may intervene in regulatory proceedings and affect regulatory outcomes.

Utility Holdings businesses and properties are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. These environmental regulations impose, among other things, restrictions, liabilities, and obligations in connection with storage, transportation, treatment, and disposal of hazardous substances and waste in connection with spills, releases, and emissions of various substances in the environment. Such airborne emissions from electric generating facilities include particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NOx), and mercury, among others. Environmental legislation/regulation also requires that facilities, sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The Company's current costs to comply with these laws and regulations are significant to its results of operations and financial condition. In addition, claims against the Company under environmental laws and regulations and other laws and regulations could result in material costs and liabilities.

There are proposals to address global climate change that would regulate carbon dioxide (CO_2) and other greenhouse gases and other proposals that would mandate an investment in renewable energy sources. Any future legislative or regulatory actions taken by the EPA or other agencies to address global climate change or mandate renewable energy sources could substantially affect both the costs and operating characteristics of the Company's fossil fuel generating plants and natural gas distribution businesses. Further, such legislation or regulatory action would likely impact the Company's generation resource planning decisions. At this time and in the absence of final legislation or regulatory mandates, 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.

With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by the Company subject to regulation, its investment in compliant infrastructure, and the associated operating costs have increased and are expected to increase in the future. As examples of the trend toward stricter regulation, the EPA is currently reviewing/revising regulations involving fly ash disposal, cooling tower intake facilities, greenhouse gases, and airborne emissions such as SO_2, NOx, and mercury. In addition, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011was signed into law on January 3, 2012 and may result in increased operating expenses and capital expenditures for the Company.

Increasing regulation could affect rates charged to customers, its costs, and its profitability.

Any additional expenses or capital incurred by the Company, as it relates to complying with increasing regulation are expected to be borne by the customers in its service territories through increased rates. Increased rates have an impact on the economic health of the communities served. New regulations could also negatively impact industries in the Company's service territory, including industries in which the Company operates.

The Company's ability to obtain rate increases and to maintain current authorized rates of return depends upon regulatory discretion, and there can be no assurance that Vectren will be able to obtain rate increases or rate supplements or earn currently authorized rates of return. Both Indiana and Ohio have passed laws allowing utilities to recover at least some of the cost of complying with federal mandates outside of a base rate proceeding.

The Company is exposed to physical and financial risks related to the uncertainty of climate change.

A changing climate creates uncertainty and could result in broad changes to the Company's service territories. These impacts could include, but are not limited to, population shifts; changes in the level of annual rainfall; changes in the weather; and changes to the frequency and severity of weather events such as thunderstorms, wind, tornadoes, and ice storms that can damage infrastructure. Such changes could impact the Company in a number of ways including the number and/or type of customers in the Company’s service territories; the demand for energy resulting in the need for additional investment in generation assets or the need to retire current infrastructure that is no longer required; an increase to the cost of providing service; and an increase in the likelihood of capital expenditures to replace damaged infrastructure.

To the extent climate change impacts a region's economic health, it may also impact the Company's revenues, costs, and capital structure and thus the need for changes to rates charged to regulated customers. Rate changes themselves can impact the economic health of the communities served and may in turn adversely affect the Company's operating results.

Utility Holdings' energy delivery operations are subject to various risks.

A variety of hazards and operations risks, such as leaks, accidental explosions, and mechanical problems are inherent in the Company's gas and electric distribution activities. If such events occur, they could cause substantial financial losses and result in loss of human life, significant damage to property, environmental pollution, and impairment of operations. The location of pipelines, storage facilities, and the electric grid near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines, or penalties or be resolved on unfavorable terms. In accordance with customary industry practices, the Company maintains insurance against a significant portion, but not all, of these risks and losses. To the extent that the occurrence of any of these events is not fully covered by insurance, it could adversely affect the Company's financial condition and results of operations.

Utility Holdings' power supply operations are subject to various risks.

The Company's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs. Such operational risks can arise from circumstances such as facility shutdowns due to equipment failure or operator error; interruption of fuel supply or increased prices of fuel as contracts expire; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; and natural disasters.

The impact of MISO participation is uncertain.

The Company is a member of the MISO, which serves the electrical transmission needs of much of the Midwest and maintains operational control over SIGECO's electric transmission facilities as well as that of other Midwest utilities. As a result of such control, SIGECO's continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted.

The need to expend capital for improvements to the regional transmission system, both to SIGECO's facilities as well as to those facilities of adjacent utilities, over the next several years is expected to be significant. The Company timely recovers its investment in certain new electric transmission projects that benefit the MISO infrastructure at a FERC approved rate of return.

Also, the MISO allocates operating costs and the cost of multi value projects throughout the region to its participating utilities such as SIGECO and such costs are significant. Adjustments to these operating costs, including adjustments that result from participants entering or leaving the MISO, could cause increases or decreases to customer bills. The Company timely recovers its portion of MISO operating expenses as tracked costs.

Wholesale power marketing activities may add volatility to earnings.

Utility Holdings' regulated electric utility engages in wholesale power marketing activities that primarily involve the offering of utility-owned or contracted generation into the MISO hourly and real time markets. As part of these strategies, the Company may also execute energy contracts that are integrated with portfolio requirements around power supply and delivery. Presently, margin earned from these activities above or below $7.5 million is shared evenly with customers. These earnings from wholesale marketing activities may vary based on fluctuating prices for electricity and the amount of electric generating capacity or purchased power available beyond that needed to meet firm service requirements. In addition, this earnings sharing approach may be modified in future regulatory proceedings.

Increases in the wholesale price of natural gas, coal, and electricity could reduce earnings and working capital.

The Company's operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal, and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. However, significant increases in the price of natural gas, coal, or purchased power may cause existing customers to conserve or motivate them to switch to alternate sources of energy as well as cause new home developers, builders, and new customers to select alternative sources of energy. Decreases in volumes sold could reduce earnings. The decrease would be more significant in the absence of constructive regulatory orders, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs. A decline in new customers could impede growth in future earnings. In addition, during periods when commodity prices are higher than historical levels, working capital costs could increase due to higher carrying costs of inventories and cost recovery mechanisms, and customers may have trouble paying higher bills leading to bad debt expenses.

Increased derivative regulation could impact results.

The Company uses natural gas derivative instruments in conjunction with procurement activities. The Company also uses interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances.

New regulations related to the use of derivatives became law in 2010. These new regulations include a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral for certain transactions. Depending on the regulations adopted by the Commodities Futures Trading Commission (CFTC) and other agencies, the Company could be required to post additional collateral with dealer counterparties for commitments and interest rate derivative transactions. Requirements to post collateral could limit cash for investment and for other corporate purposes or could increase debt levels. In addition, a requirement for counterparties to post collateral could result in additional costs associated with executing transactions, thereby decreasing profitability. An increased collateral requirement could also reduce the Company's ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. The new regulations may also limit the pool of potential counterparties.

The law provides for an exception from these clearing and cash collateral requirements for commercial end-users. Significant rule-making by numerous governmental agencies, particularly the CFTC, must be adopted in the near term so that the restrictions, limitations, and requirements contemplated by the new law can be implemented. The Company will continue to evaluate the impact as these rulemaking and interpretations become available and whether any exemption will apply to the Company's use of derivative instruments.

From time to time, Utility Holdings is subject to material litigation and regulatory proceedings.

From time to time, the Company may be subject to material litigation and regulatory proceedings including matters involving compliance with state and federal laws, regulations or other matters. There can be no assurance that the outcome of these matters will not have a material adverse effect on the Company's business, prospects, results of operations, or financial condition.

The investment performance of Vectren's pension plan holdings and other factors impacting pension plan costs could impact the Company's liquidity and results of operations.

The costs associated with Vectren's retirement plans are dependent on a number of factors, such as the rates of return on plan assets; discount rates; the level of interest rates used to measure funding levels; changes in actuarial assumptions; future government regulation; and Vectren contributions. In addition, Vectren could be required to provide for significant funding of these defined benefit pension plans. Vectren relies on Utility Holdings to fund a majority of the contributions to these plans. Such cash funding obligations could have a material impact on liquidity by reducing cash flows for other purposes and could negatively affect results of operations.

Catastrophic events, such as cyber-attacks, terrorist attacks, acts of war, and acts of God, may adversely affect the Company's facilities and operations.

Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornados, terrorist acts, cyber-attacks, or similar occurrences could adversely affect the Company's facilities, operations, financial condition and results of operations. Either a direct act against company-owned generating facilities or transmission and distribution infrastructure or an act against the infrastructure of neighboring utilities or interstate pipelines that are used by the Company to transport power and natural gas could result in the Company being unable to deliver natural gas or electricity for a prolonged period. Further, the Company relies on information technology networks and systems to operate its generating facilities, engage in asset management activities, and process, transmit and store electronic information. Security breaches of this information technology infrastructure, including cyber-attacks and cyber-terrorism, could lead to system disruptions, generating facility shutdowns or unauthorized disclosure of confidential information. In the event of a severe disruption resulting from such events, the Company has contingency plans and employs crisis management to respond and recover operations. Despite these measures, if such an attack or security breach were to occur, results of operations and financial condition could be materially adversely affected.

Workforce risks could affect Utility Holdings' financial results.

The Company is subject to various workforce risks, including but not limited to, the risk that it will be unable to attract and retain qualified personnel; that it will be unable to effectively transfer the knowledge and expertise of an aging workforce to new personnel as those workers retire; that it will be unable to react to a pandemic illness; and that it will be unable to reach collective bargaining arrangements with the unions that represent certain of its workers, which could result in work stoppages.

The performance of Vectren's nonutility businesses may impact Utility Holdings.

Execution of Vectren's nonutility business strategies and the success of efforts to invest in and develop new opportunities in the nonutility business area are subject to a number of risks.

Related to Vectren's nonutility energy marketing activities, ProLiance is a 61 percent owned energy marketing affiliate of Vectren. ProLiance relies on long-term firm transportation and storage contracts with pipeline companies to deliver natural gas to its customer base which includes the Company's Indiana utilities. Those contracts are optimized by balancing physical and financial markets and summer and winter time horizons. Therefore, recovery of these contracts' fixed costs is dependent on a number of factors, including the health of the economy, weather, changes in the availability and location of natural gas supply and related transmission assets, the price of natural gas, and the availability of credit. Optimization opportunities at current market prices or a deterioration of the customer base may result in the inability to fully recover these fixed price obligations. Recent market conditions have compressed optimization opportunities, and ProLiance has operated at a loss. If current market conditions continue, resulting in continued depressed asset optimization opportunities, losses could continue in future years should ProLiance be unable to adjust to the current market conditions or be unsuccessful in renegotiating its transportation and storage contracts over time.

Related to Vectren's nonutility coal mining activities, Vectren Fuels is wholly owned by Vectren and is supplier of coal to Utility Holdings' Indiana electric utility. Risks specific to Vectren's coal mining strategies include, but are not limited to, failure to fully access coal at owned mines; failure to operate mines in accordance with MSHA guidelines and regulations; increased coal mining industry regulation; failure to negotiate and execute new sales contracts; failure to manage coal mining production and production costs and other risks in response to changes in demand; changes in market demand for coal; and unanticipated changes in coal commodity prices.

In addition, there are other risks impacting Vectren's nonutility operations including the effects of weather; failure of installed performance contracting products to operate as planned; failure to properly estimate the cost to construct projects; failure to develop or obtain gas storage field and mining property; potential legislation that may limit CO2 and other greenhouse gas emissions; creditworthiness of customers and joint venture partners; changes in federal, state or local legal requirements, such as changes in tax laws or rates; and changing market conditions.

Credit ratings of individual entities within a consolidated organization can be influenced by changes in business prospects and developments of other entities within that organization. Thus, material adverse developments affecting those other entities related to Vectren could result in a downgrade in Utility Holdings' credit ratings or outlook, limit its ability to access the debt markets, bank financing and commercial paper markets and, thus, its liquidity.

Vectren's nonutility businesses support Utility Holdings' utilities pursuant to service contracts by providing natural gas supply services, coal, and infrastructure services. In most instances, Vectren's ability to maintain these service contracts depends upon regulatory discretion and negotiation with interveners, and there can be no assurance that it will be able to obtain future service contracts, or that existing arrangements will not be revisited.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Gas Utility Services

Indiana Gas owns and operates four active gas storage fields located in Indiana covering 58,100 acres of land with an estimated ready delivery from storage capability of 5.6 BCF of gas with maximum peak day delivery capabilities of 143,500 MCF per day. Indiana Gas also owns and operates three liquefied petroleum (propane) air-gas manufacturing plants located in Indiana with the ability to store 1.5 million gallons of propane and manufacture for delivery 33,000 MCF of manufactured gas per day. In addition to its company owned storage and propane capabilities, Indiana Gas has contracted with ProLiance for 16.5 BCF of interstate natural gas pipeline storage service with a maximum peak day delivery capability of 245,867 MMBTU per day. Indiana Gas' gas delivery system includes 13,000 miles of distribution and transmission mains, all of which are in Indiana except for pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported by Indiana Gas to ultimate customers in Indiana.

SIGECO owns and operates three active underground gas storage fields located in Indiana covering 6,100 acres of land with an estimated ready delivery from storage capability of 6.3 BCF of gas with maximum peak day delivery capabilities of 108,000 MCF per day. In addition to its company owned storage delivery capabilities, SIGECO has contracted with ProLiance for 0.4 BCF of interstate pipeline storage service with a maximum peak day delivery capability of 16,812 MMBTU per day. SIGECO's gas delivery system includes 3,200 miles of distribution and transmission mains, all of which are located in Indiana.

VEDO owns and operate three liquefied petroleum (propane) air-gas manufacturing plants, all of which are located in Ohio. The plants can store 0.5 million gallons of propane, and the plants can manufacture for delivery 52,200 MCF of manufactured gas per day. In addition to its propane delivery capabilities, VEDO has contracted for 11.8 BCF of natural gas delivery service with a maximum peak day delivery capability of 246,080 MMBTU per day. While the Company still has title to this delivery capability, it has released it to those retail gas marketers now supplying VEDO's customers with natural gas, and those suppliers are responsible for the demand charges. VEDO's gas delivery system includes 5,500 miles of distribution and transmission mains, all of which are located in Ohio.

Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2011, was rated at 1,298 MW. SIGECO's coal-fired generating facilities are the Brown Station with two units of 490 MW of combined capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Culley Station with two units of 360 MW of combined capacity, and Warrick Unit 4 with 150 MW of capacity. Both the Culley and Warrick Stations are located in Warrick County near Yankeetown, Indiana. SIGECO's gas-fired turbine peaking units are: two 80 MW gas turbines (Brown Unit 3 and Brown Unit 4) located at the Brown Station; two Broadway Avenue Gas Turbines located in Evansville, Indiana with a combined capacity of 115 MW (Broadway Avenue Unit 1, 50 MW and Broadway Avenue Unit 2, 65 MW); and two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW. The Brown Unit 3 and Broadway Avenue Unit 2 turbines are also equipped to burn oil. Total capacity of SIGECO's six gas turbines is 295 MW, and they are generally used only for reserve, peaking, or emergency purposes due to the higher per unit cost of generation. In 2009, SIGECO, with IURC approval, purchased a landfill gas electric generation project in Pike County, Indiana with a total capability of 3 MW.

SIGECO's transmission system consists of 989 circuit miles of 345Kv, 138Kv and 69Kv lines. The transmission system also includes 35 substations with an installed capacity of 4,863 megavolt amperes (Mva). The electric distribution system includes 4,281 pole miles of lower voltage overhead lines and 372 trench miles of conduit containing 1,999 miles of underground distribution cable. The distribution system also includes 96 distribution substations with an installed capacity of 2,929 Mva and 54,000 distribution transformers with an installed capacity of 2,349 Mva.

SIGECO owns utility property outside of Indiana approximating nine miles of 138,000 volt electric transmission line, which is included in the 989 circuit miles discussed above, located in Kentucky and which interconnects with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky.

Property Serving as Collateral

SIGECO's properties are subject to the lien of the First Mortgage Indenture dated as of April 1, 1932, between SIGECO and Bankers Trust Company, as Trustee, and Deutsche Bank, as successor Trustee, as supplemented by various supplemental indentures.

ITEM 3. 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 financial statements are included in "Item 8 Financial Statements and Supplementary Data."

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.
PART II

ITEM 5. MARKET FOR COMPANY'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES
Common Stock Market Price

All of the outstanding shares of Utility Holdings' common stock are owned by Vectren. Utility Holdings' common stock is not traded. There are no outstanding options or warrants to purchase Utility Holdings' common equity or securities convertible into Utility Holdings' common equity. Additionally, Utility Holdings has no plans to publicly offer its common equity securities.

Dividends Paid to Parent

During 2011, Utility Holdings paid dividends of $22.9 million to its parent company in each of the first through fourth quarters.

During 2010, Utility Holdings paid dividends to its parent company in the first through fourth quarters totaling $19.1 million, $20.3 million, $20.3 million, and $28.1 million, respectively.

In the first quarter of 2012, Utility Holdings paid a $25.0 million dividend to its parent company.

Dividends on shares of common stock are payable at the discretion of the board of directors out of legally available funds. Future payments of dividends, and the amounts of these dividends, will depend on the Company's financial condition, results of operations, capital requirements, and other factors.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data is derived from the Company's audited consolidated financial statements and should be read in conjunction with those financial statements and notes thereto contained in this Form 10-K.

	Year Ended December 31,				
(In millions)	2011	2010	2009	2008	2007
Operating Data:					
Operating revenues	$1,457.0	$1,563.7	$1,596.2	$1,958.7	$1,759.0
Operating income	281.8	277.0	238.0	254.6	244.4
Net income	122.9	123.9	107.4	111.1	106.5
Balance Sheet Data:					
Total assets	$3,974.5	$3,924.5	$3,823.1	$3,838.1	$3,643.7

Long-term debt - net of current maturities & debt subject to tender	1,208.2	1,024.8	1,254.8	1,065.1	1,062.6
Common shareholder's equity	1,346.6	1,315.4	1,274.7	1,242.9	1,090.4

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

Utility Holdings generates revenue primarily from the delivery of natural gas and electric service to its customers. Utility Holdings' primary source of cash flow results from the collection of customer bills and the payment for goods and services procured for the delivery of gas and electric services.

Vectren 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 Utility Holdings' SEC filings.

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto.

Executive Summary of Consolidated Results of Operations

During 2011, Utility Holdings earned $122.9 million, compared to $123.9 million earned in 2010 and $107.4 million earned in 2009. The results in 2011 reflect an increase in earnings from electric operations and slightly lower earnings from gas operations. Results also include an unfavorable income tax adjustment associated with the sale of Vectren Source, a former wholly owned subsidiary of Vectren. The increase in 2010 compared to 2009 results from the return of large customer usage, summer cooling weather that was significantly warmer than normal and the prior year, and lower operating expenses.

Gas utility services

The gas utility segment earned $52.5 million during the year ended December 31, 2011, compared to earnings of $53.7 million in 2010 and $50.2 million in 2009. Results over the periods presented have been impacted by continued growth in large customer margin and return on bare steel, cast iron, and distribution riser replacement activities in Ohio. In 2011 increased operating expenses associated with planned maintenance activities, environmental remediation efforts, and a brief work stoppage related to bargaining unit labor negotiations unfavorably impacted year over year trends. In 2010 results were favorably impacted by the phased implementation of a straight fixed variable rate design in the Ohio service territory and by lower operating expenses.

Electric utility services

The electric operations earned $65.0 million during 2011, compared to $60.9 million in 2010 and $48.3 million in 2009. The year ended 2011 has been positively impacted by new electric base rates implemented on May 3, 2011 and negatively impacted by summer weather that, while warmer than normal, was cooler than the extreme summer temperatures in 2010. Earnings in 2011 were also reduced by increased power supply operating expenses associated with planned electric generating maintenance activities. The increase in 2010 compared to 2009 is principally due to extreme summer weather and increased large customer margins.

Management estimates the impact of weather on electric margin, compared to normal temperatures, to be approximately $3.0 million favorable in 2011. This compares to 2010, where management estimated a $10.4 million favorable impact on margin compared to normal. In 2010 summer cooling weather was 34 percent warmer than normal. In 2009, there was mild cooling weather, and management estimates the impact on electric margin to be $4.8 million unfavorable compared to normal in that year. Although summer temperatures were warmer than normal in 2011, year over year compared to 2010, there was a decline in earnings of approximately $4.4 million after tax, or $0.05 per share. In 2010 compared to 2009, there was an estimated increase of $9.0 million after tax, or $0.11 per share, due to electric weather.

Other utility operations

In 2011 earnings from other utility operations were $5.4 million compared to $9.3 million in 2010 and $8.9 million in 2009. The decrease in 2011 is primarily due to a higher effective income tax rate. Pursuant to tax sharing arrangements with Vectren, the higher income tax rate results primarily from the revaluation of existing deferred income taxes as a result of the fourth quarter sale of Vectren Source, a former wholly owned and nonutility subsidiary of Vectren. The charge to income taxes as a result of the revaluation was approximately $2.8 million.

The Regulatory Environment

Gas and electric operations, with regard to retail rates and charges, terms of service, accounting matters, financing, and certain other operational matters specific to its Indiana customers (the operations of SIGECO and Indiana Gas), are regulated by the IURC. The retail gas operations of VEDO are subject to regulation by the PUCO.

Over the last five years, orders establishing new base rates have been received by each utility. SIGECO's electric territory received an order in April 2011, effective May 2011, and its gas territory received an order in August 2007. Indiana Gas received its most recent base rate order in February 2008 and VEDO in January 2009. The orders authorize a return on equity ranging from 10.15 percent to 10.40 percent. The authorized returns reflect the impact of innovative rate design strategies having been authorized by these state commissions. Outside of a full base rate proceeding, these innovative approaches to some extent mitigate the impacts of investments in government-mandated projects, operating costs that are volatile or that increase with government mandates, and changing consumption patterns. In addition to timely gas and fuel cost recovery, approximately $41 million of the approximate $313 million in Other operating expenses incurred during 2011 are subject to a recovery mechanism outside of base rates. In 2011, state laws in both Indiana and Ohio were passed that expand the ability of utilities to recover certain costs of federally mandated projects, and in Ohio other projects, outside of a base rate proceeding. Therefore, utilization of these mechanisms will likely increase in the coming years.

Rate Design Strategies

Sales of natural gas and electricity to residential and commercial customers are seasonal and are impacted by weather. Trends in average use among natural gas residential and commercial customers have tended to decline as more efficient appliances and furnaces are installed and the Company's utilities have implemented conservation programs. In the Company's two Indiana natural gas service territories, normal temperature adjustment (NTA) and lost margin recovery mechanisms largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns. The Ohio natural gas service territory has a straight fixed variable rate design. This rate design, which was fully implemented in February 2010, mitigates most of the Ohio service territory's weather risk and risk of decreasing consumption. Prior to the implementation of this rate design, the Ohio service territory had a lost margin recovery mechanism. In all natural gas service territories, commissions have authorized bare steel and cast iron replacement programs. SIGECO's electric service territory currently recovers certain transmission investments outside of base rates. The electric service territory has neither an NTA nor a decoupling mechanism; however, rate designs provide for a lost margin recovery mechanism that works in tandem with conservation initiatives.

Tracked Operating Expenses

Gas costs and fuel costs incurred to serve Indiana customers are two of the Company's most significant operating expenses. Rates charged to natural gas customers in Indiana contain a gas cost adjustment (GCA) clause. The GCA clause allows the Company to timely charge for changes in the cost of purchased gas, inclusive of unaccounted for gas expense based on historical experience. Electric rates contain a fuel adjustment clause (FAC) that allows for timely adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to an approved variable benchmark based on NYMEX natural gas prices, is also timely recovered through the FAC.

GCA and FAC procedures involve periodic filings and IURC hearings to establish the amount of price adjustments for a designated future period. The procedures also provide for inclusion in later periods of any variances between actual recoveries representing the estimated costs and actual costs incurred.

The IURC has also applied the statute authorizing GCA and FAC procedures to reduce rates when necessary to limit net operating income to a level authorized in its last general rate order through the application of an earnings test. These earnings tests have not had any material impact to the Company's recent operating results and are not expected to have any material impact in the foreseeable future. Since October of 2008, the Company has not been the supplier of natural gas in its Ohio territory.

In Indiana, gas pipeline integrity management costs, costs to fund energy efficiency programs, MISO costs, and the gas cost component of uncollectible accounts expense based on historical experience are recovered by mechanisms outside of standard base rate recovery. Certain operating costs, including depreciation, associated with operating environmental compliance equipment at electric generation facilities and regional electric transmission investments are also recovered outside of base rates when the associated asset is recovered outside of base rates. In Ohio, expenses such as uncollectible accounts expense, costs associated with exiting the merchant function, and costs associated with a distribution replacement program are subject to recovery outside of base rates. Revenues and margins are also impacted by the collection of state mandated taxes, which primarily fluctuate with gas and fuel costs.

See the Rate and Regulatory Matters section of this discussion and analysis for more specific information on significant proceedings involving the Company's utilities over the last three years.

Operating Trends
Margin

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

	Year Ended December 31,		
(In millions)	2011	2010	2009
Gas utility revenues	$819.1	$954.1	$1,066.0
Cost of gas sold	375.4	504.7	618.1
Total gas utility margin	$443.7	$449.4	$447.9
Margin attributed to:			
Residential & commercial customers	$375.2	$384.7	$387.2
Industrial customers	56.4	52.2	46.6
Other	12.1	12.5	14.1
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	99.9	106.2	106.5
Industrial customers	97.0	90.8	78.0
Total sold & transported volumes	196.9	197.0	184.5

Over the three years ended December 31, 2011, volumes sold to residential and commercial customers have been impacted by weather, lower gas prices, conservation initiatives, and changing consumption patterns. However, the impact on margin has been generally offset as planned by rate design strategies. Large customer volumes were impacted by the recession, falling approximately 15 percent in 2009. With the economy stabilizing in 2010, volumes in 2010 returned to pre-recession levels with additional growth in 2011. The recovery from the recession and increasing ethanol production were the principal reasons for the change in large customer margin over the years presented. The average cost per dekatherm of gas purchased during 2011 was $5.30, compared to $5.99 in 2010 and $5.97 in 2009.

Gas utility margins were $443.7 million for year ended December 31, 2011, and compared to 2010 decreased $5.7 million. Margin decreased $8.0 million year over year due to lower revenue taxes and operating costs recovered in margin. Management estimates a 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 $2.7 million year over year. Large customer margin, net of the impacts of regulatory initiatives and tracked costs, increased by $3.8 million due primarily to ethanol producers.

For the year ended December 31, 2010, gas utility margins increased $1.5 million compared to 2009. Management estimates an increase of $2.4 million due to Ohio rate design changes, as described below. Large customer margin, net of the impacts of regulatory initiatives and tracked costs, increased by $5.7 million due primarily to increased volumes sold. Margin decreased $1.9 million due to lower miscellaneous revenues and other revenues associated with lower gas costs. The remaining decrease is primarily due to a $5.0 million decrease for lower operating expenses and revenue taxes directly recovered in margin.

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. This rate design 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 of the timing of this conversion, margin in 2010 was favorably impacted by the volumetric rate design in place during the peak delivery winter months of January and the first half of February. Margin recognized in 2011 reflects the full implementation of the rate design which resulted in a decrease in margin in 2011 compared to 2010.

Electric Utility Margin (Electric utility revenues less Cost of fuel & purchased power)
Electric utility margin and volumes sold by customer type follows:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Electric utility revenues	$635.9	$608.0	$528.6
Cost of fuel & purchased power	240.4	235.0	194.3
Total electric utility margin	$395.5	$373.0	$334.3
Margin attributed to:			
Residential & commercial customers	$255.8	$241.2	$224.6
Industrial customers	101.6	97.1	81.7
Municipals & other customers	8.5	8.5	7.3
Subtotal: Retail	$365.9	$346.8	$313.6
Wholesale margin	29.6	26.2	20.7
Total electric utility margin	$395.5	$373.0	$334.3
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,827.2	2,964.0	2,760.8
Industrial customers	2,744.8	2,630.3	2,258.9
Municipals & other	22.8	22.6	20.0
Total retail & firm wholesale volumes sold	5,594.8	5,616.9	5,039.7

Retail
Electric retail utility margins were $–––365.9 million for the year ended December 31, 2011 and compared to 2010 increased by $19.1 million. The impact of new base rates increased margin $23.7 million. 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 $7.4 million. Margin increased $2.4 million year over year due to increased MISO operating costs that are directly recovered in margin.

In 2010, electric retail utility margins increased $33.2 million compared to 2009. Management estimates the impact of warmer than normal weather to have increased residential and commercial margin $14.2 million year over year. Management also estimates industrial margins, net of the impacts of regulatory initiatives and recovery of tracked costs, to have increased approximately $12.8 million year over year due primarily to increased volumes. Margin among the customer classes associated with returns on pollution control investments increased $3.4 million, and margin associated with tracked costs such as recovery of MISO and pollution control operating expenses increased $4.1 million.

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:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Transmission system margin	$23.5	$18.8	$14.6
Off-system margin	6.1	7.4	6.1
Total wholesale margin	$29.6	$26.2	$20.7

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 $23.5 million during 2011, compared to $18.8 million in 2010 and $14.6 million in 2009. 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 connects Vectren's A.B. Brown Generating Station to a station in Indiana owned by Duke Energy to the north and will connect 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 $74 million as of December 31, 2011. The north leg of this expansion was placed in service in November 2010, and the south leg of this project is expected to be operational in 2012.

For the year ended December 31, 2011, margin from off-system sales was $6.1 million, compared to $7.4 million in 2010 and $6.1 million in 2009. 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 586.7 GWh in 2011, compared to 587.6 GWh in 2010, and 603.6 GWh in 2009.

Operating Expenses

Other Operating

For the year ended December 31, 2011, Other operating expenses were $313.1 million, and compared to 2010 reflect an increase of $13.9 million. The increase is primarily attributable to higher electric power supply operating expenses. Such expenses increased $10.8 million year over year with $6.9 million attributed to planned outage maintenance and $3.1 million attributed to variable production costs. The remaining variance is primarily attributable to higher planned energy delivery costs.

For the year ended December 31, 2010, Other operating expenses decreased $5.4 million compared to 2009. Excluding expenses tracked directly in margin, operating costs decreased $7.9 million. There was a $3.0 million reduction in Indiana uncollectible accounts expense. And in 2009, the Company incurred $5.3 million related to environmental remediation efforts.

Depreciation & Amortization

For the year ended December 31, 2011, depreciation and amortization expense was $192.3 million, compared to $188.2 million in 2010 and $180.9 million in 2009. These increases reflect utility investments placed into service. The higher deprecation as a result of increasing rate base was offset by lower amortization of certain deferred costs pursuant to the May 2011 electric base rate order. Such decreased amortizations were $2.5 million in 2011.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $5.6 million in 2011 compared to 2010 and decreased $0.7 million in 2010 compared to 2009. The decreases are 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 2010. These taxes are primarily revenue-related taxes and are offset dollar-for-dollar with lower gas utility revenues.

Other Income-Net

Other income-net reflects income of $4.3 million in 2011, compared to $5.4 million in 2010 and $7.8 million in 2009. The declines among the years principally reflect lower returns associated with investments that fund benefit plans. The earnings in 2009 reflect the partial recovery of those investments from the significant market declines in 2008 associated with the recession.

Interest Expense

For year ended December 31, 2011, interest expense was $80.3 million, and is a slight decrease compared to 2010. The decrease is primarily due to fourth quarter 2011 refinancing activity in which $250 million of long-term debt with a 6.625 percent interest rate matured and was replaced with $150 million of new long-term debt with an average interest rate of 5.12 percent and $100 million of short-term borrowings. During the fourth quarter, the Company also called $96.2 million of long-term debt at a rate of 5.95 percent and replaced that issuance in February 2012 with new debt at a rate of 5.0 percent. The impacts of refinancing at lower rates will decrease interest more significantly in 2012.

The $2.2 million increase in 2010 compared to 2009 reflects the impact of long-term financing transactions completed in 2009, offset by lower interest from less debt outstanding overall. The long-term financing transactions completed in 2009 include a second quarter issuance by Utility Holdings of $100 million in unsecured eleven year notes with an interest rate of 6.28 percent and a third quarter completion by SIGECO of a $22.3 million debt issuance of 31 year tax exempt first mortgage bonds with an interest rate of 5.4 percent.

Income Taxes

In 2011, federal and state income taxes were $82.9 million, compared to $77.1 million in 2010 and $59.2 million in 2009. The $5.8 million increase in 2011 primarily reflects a higher effective income tax rate. Pursuant to tax sharing arrangements with Vectren, the higher income tax rate includes a $2.8 million charge that results from the revaluation of existing deferred income taxes as a result of the fourth quarter sale of Vectren Source, a former wholly owned and nonutility subsidiary of Vectren.

Federal and state income taxes increased $17.9 million in 2010 compared to 2009. The increase is primarily impacted by greater pre-tax income in 2010 and no manufacturing tax deduction in 2010 as a result of significant bonus depreciation driving down qualifying income. In addition, the lower effective tax rate in 2009 reflects a greater share of taxable income in states with low, or no, state income taxes.

Legislative Matters

Pipeline Safety Law

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

The Company continues to study the impact of the new law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the new law is expected to result in further investment in pipeline inspections, and where necessary, additional modernization of pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow to approximately $9 million annually, with $6 million attributable to the Indiana operations. The Company expects to seek recovery under Senate Bill 251 referenced below, or such costs may be recoverable through current tracking mechanisms. Capital investments, driven by the pipeline safety regulations, associated with the Company's Indiana gas utilities are expected to be approximately $80 million over the next five years, which would likely qualify as federally mandated regulatory requirements. In Ohio, capital investments are expected to be approximately $55 million over the next five years. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 in Ohio (referenced below).

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 or financial condition as the decrease in Deferred tax liabilities was generally offset by a $17.1 million decrease in Regulatory assets.

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 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 general rate case. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred for recovery in the utility's next general rate case. 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.

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. Before the impacts of efficiency measures, the Company currently stands at approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investments. The Company continues to evaluate whether to participate in this voluntary program.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was 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. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, post in service carrying costs and property taxes for its approximate $25 million 2012 capital expenditure program. The capital expenditure program includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with PUCO rules, regulations and orders. A procedural schedule associated with the filing has not yet been set.

Environmental Matters

Air Quality

Cross-State Air Pollution Rule (Formerly Clean Air Interstate Rule (CAIR))
On July 7, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSPAR is the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015.

In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2and NOx allowances, CSPAR reduces the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSPAR sets individual state caps for SO2and NOx emissions. However, unlike CAIR in which states allocated allowances through state implementation plans, CSPAR allowances were allocated to individual units directly through the federal rule. As finalized, CSAPR requires a 71 percent reduction of SO2 emissions compared to 2005 national levels and a 52 percent reduction of NOx emissions compared to 2005 national levels and that such reductions are to be achieved with initial step reductions beginning January 1, 2012, with final compliance to be achieved in 2014. Multiple administrative and judicial challenges have been filed, including requests to stay CSPAR's implementation.

On December 30, 2011, the Court granted a stay of CSPAR and ordered expedited briefing schedules be submitted by January 18, 2012, that would allow for completion of briefing and a hearing in April 2012. Two primary issues are before the Court for review: (1) EPA's use of air modeling data (as opposed to exclusive reliance on actual monitoring data) to support state contribution levels, and (2) EPA's allocation of allowances directly through a federal implementation plan as opposed to setting state caps and providing states the opportunity to submit individual state implementation plans. In addition, there are initiatives in the Congress that, if adopted, would suspend CSPAR's implementation.

Utility Hazardous Air Pollutants (HAPs) Rule
On December 21, 2011, the EPA finalized the Utility HAPs rule. The HAPs Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The HAPs rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium) and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (early 2015). Initiatives to suspend CSPAR's implementation by the Congress also apply to the implementation of the HAPs Rule.

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

filters, and an SO2 scrubber at its generating facility that is jointly owned with 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 obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

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

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in CSPAR and the Utility HAPs Rule. Based upon an initial review of the final rules, including minor revisions made to CSPAR in October 2011, 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 and additional operating expenses could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Water

Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2012. Depending on the final rule and on the Company's facts and circumstances, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations would likely qualify as federally mandated regulatory requirements under Indiana Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 given oversight hearings, congressional interest, and other factors.

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

Climate Change

The Company is committed to responsible environmental stewardship and conservation efforts and if a national climate change policy is implemented believes it should have the following elements:

- An inclusive scope that involves all sectors of the economy and sources of greenhouse gases, and recognizes early actions and investments made to mitigate greenhouse gas emissions;
- Provisions for enhanced use of renewable energy sources as a supplement to base load coal generation including effective energy conservation, demand side management, and generation efficiency measures;
- A flexible market-based cap and trade approach with zero cost allowance allocations to coal-fired electric generators. The approach should have a properly designed economic safety valve in order to reduce or eliminate

extreme price spikes and potential price volatility. A long lead time must be included to align nearer-term technology capabilities and expanded generation efficiency and other enhanced renewable strategies, ensuring that generation sources will rely less on natural gas to meet short term carbon reduction requirements. This new regime should allow for adequate resource and generation planning and remove existing impediments to efficiency enhancements posed by the current New Source Review provisions of the Clean Air Act;

- Inclusion of incentives for investment in advanced clean coal technology and support for research and development;
- A strategy supporting alternative energy technologies and biofuels and increasing the domestic supply of natural gas to reduce dependence on foreign oil and imported natural gas; and
- The allocation of zero cost allowances to natural gas distribution companies if those companies are required to hold allowances for the benefit of the end use customer.

The Company emits greenhouse gases (GHG) primarily from its fossil fuel electric generation plants. The Company uses methodology described in the Acid Rain Program (under Title IV of the Clean Air Act) to calculate its level of direct CO_2 emissions from its fossil fuel electric generating plants. The Company's direct CO_2 emissions from its plants over the past 5 years are represented below:

(in thousands)	2011	2010	2009	2008	2007
Direct CO_2 Emissions (tons)	5,645	6,120	5,500	8,029	7,995

Based on data made available through the Electronic Greenhouse Gas Reporting Tool (e-GRRT) maintained by the EPA, the Company's direct CO_2 emissions from its fossil fuel electric generation that report under the Acid Rain Program were less than one half of one percent of all emissions in the United States from similar sources. Emissions from other Company operations, including those from its natural gas distribution operations and the greenhouse gas emissions the Company is required to report on behalf of its end use customers, are similarly available through the EPA's e-GRRT database and reporting tool.

Current Initiatives to Increase Conservation & Reduce Emissions

The Company is committed to a policy that reduces greenhouse gas emissions and conserves energy usage. Evidence of this commitment includes:

- Focusing the Company's mission statement and purpose on corporate sustainability and the need to help customers conserve and manage energy costs;
- Building a renewable energy portfolio to complement base load coal-fired generation in advance of mandated renewable energy portfolio standards;
  - Implementing conservation initiatives in the Company's Indiana and Ohio gas utility service territories;
  - Implementing conservation and demand side management initiatives in the electric service territory;
- Evaluating potential carbon requirements with regard to new generation, other fuel supply sources, and future environmental compliance plans;
- Reducing the Company's carbon footprint by measures such as utilizing hybrid vehicles and optimizing generation efficiencies by utilizing dense pack technology.

Legislative Actions & Other Climate Change Initiatives

In April 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 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The Company anticipates additional EPA rulemaking related to new generation sources and significant modifications to existing sources, but the timetable remains uncertain.

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 and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in 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.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it reasonably expects to incur totaling approximately $41.6 million ($23.1 million at Indiana Gas and $18.5 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. SIGECO 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 another site subject to a lawsuit that has been settled. In November 2011, 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 settlement agreements with all known insurance carriers and has recorded approximately $15.1 million of expected insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require 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 December 31, 2011 and 2010, respectively, approximately $6.5 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.

Jacobsville Superfund Site

On July 22, 2004, the EPA listed the Jacobsville Neighborhood Soil Contamination site in Evansville, Indiana, on the National Priorities List under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The EPA has identified four sources of historic lead contamination. These four sources shut down manufacturing operations years ago. When drawing up the boundaries for the listing, the EPA included a 250 acre block of properties surrounding the Jacobsville neighborhood, including the Company's operations center. Vectren's property has not been named as a source of the lead contamination. Vectren's own soil testing, completed during the construction of the operations center, did not indicate that the Vectren property contains lead contaminated soils above industrial cleanup levels. At this time, it is anticipated that the EPA may request additional soil testing at some future date.

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. 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 would be initiated.

Coal Procurement Procedures

Vectren South submitted a request for proposal in April 2011 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 case, a sub docket proceeding was established to review the Company's prospective coal procurement procedures, and the Company submitted evidence related to its recent request for proposal (RFP) and those coal procurement procedures to the IURC in September 2011. In October 2011, the OUCC filed its testimony which, while suggesting enhancements to the process to be considered, does not challenge the results of the RFP and the resulting new contracts. All hearings were completed in December 2011 and an order is expected in early 2012.

Vectren South Electric Fuel Cost Reduction

On December 5, 2011 within the quarterly Fuel Adjustment Clause (FAC) filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating the impact of lower cost coal contracts to be effective after 2012. In the spring of 2011, Vectren secured contracts for lower coal costs through a formal bidding process. This lower-priced coal is expected to start being delivered and used at Vectren's power plants by late 2012 to early 2013 and beyond. The agreement to accelerate savings into early 2012 means that the existing 2012 coal costs that are above the new, lower prices will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. This deferral also includes a reduction to the coal inventory balance at December 31, 2011 of approximately $17.7 million to reflect existing inventory at the new, lower price. The IURC approved this proposal on January 25, 2012, with an impact to customer's rates effective February 1, 2012.

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, and include some for large industrial customers.

Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South service territory that complies with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011. On January 26, 2012, the Company filed with the IURC a proposal for a small customer lost margin recovery mechanism within the existing Demand Side Management Adjustment (DSMA). The proposal includes a request for recovery of the $1 million deferred in 2011, and a request for continued deferral of lost margins in 2012 until such point as these lost margins are included in DSMA rates. The procedural schedule has not been set in this filing, but the Company expects an order in 2012.

Vectren South Electric Dense Pack Filing

On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $19 million has been invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. Indiana statute provides for timely recovery of investments, with a return, in instances where the investment increases the efficiency of existing generating plants that are fueled by coal. Several parties have intervened in the case and are requesting that the IURC deny recovery of these project costs outside of a base rate proceeding. A hearing was held by the IURC in February 2012 and proposed orders are to be submitted by the parties in March 2012. An order is expected later in 2012.

Vectren North Reporting Location Consolidation Proceeding

Vectren North implemented a reporting location consolidation plan in 2011 and closed certain locations throughout the North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others filed a formal complaint with the IURC claiming that the consolidation and simultaneous closing by Vectren North of select reporting locations endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. These parties have asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012, and the Company expects the IURC to act some time in 2012.

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. On August 18, 2011, the IURC issued an order approving the settlement as filed, granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

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 commenced on April 1, 2011. The results of that auction were approved by the PUCO on January 19, 2011. Vectren Source, the Company's former 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. Each tranche of customers equates to approximately 28,000 customers. As per the terms of the plan approved by the PUCO, because no application for a full exit of the merchant function was neither sought nor approved by April 1, 2011, VEDO conducted a third retail auction on January 31, 2012 to address the 12-month term beginning April 1, 2012. The results of that auction were approved by the PUCO on February 1, 2012. Consistent with current practice, customers 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. VEDO's gas costs were $12.7 million, $89.5 million, and $157.4 million for the twelve months ended December 31, 2011, 2010, and 2009, respectively, while revenue taxes were $11.5 million, $15.6 million, and $18.6 million, respectively. Therefore, Gas utility revenues resulting from VEDO's exit of the merchant function decreased $80.9 million in 2011 compared to 2010 and $70.9 million in 2010 compared to 2009.

Impact of Recently Issued Accounting Guidance

Other Comprehensive Income (OCI)

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 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 will adopt this guidance for its quarterly reporting period ending March 31, 2012. The adoption of this guidance will have no material impacts to the Company's financial statements.

Goodwill Testing

In September 2011, the FASB issued new accounting guidance regarding testing goodwill for impairment. The new guidance will allow the Company an option to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Using the new guidance, the Company no longer would be required to calculate the fair value of a reporting unit unless the Company determines, based on that qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The new guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of this guidance will have no material impact to the Company's financial statements.

Multiemployer Pension Plan Disclosures

In September 2011, the FASB issued new accounting guidance that requires enhanced disclosures regarding an employer's participation in multiemployer pension plans. Although the Company doesn't participate in multiemployer plans, Utility Holdings participates in the parent company's single-employer pension plan and in accordance with FASB guidance accounts for its participation in the overall pension plan as if the Company was participating in a multiemployer pension plan. Under this new multiemployer plan guidance, the Company is required to disclose the name of the parent plan and the amount of contributions made to the plan in each period for which an income statement is presented. The Company has adopted this guidance for the Company's 2011 financial statements as required.

Fair Value Measurement and Disclosure

In May 2011, the FASB issued accounting guidance to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and International Financial Reporting Standards (IFRS). The amendments are not intended to change the application of the current fair value requirements, but to clarify the application of existing requirements. The guidance does change particular principles or requirements for measuring fair value or disclosing information about fair value measurements. To improve consistency, language has been changed to ensure that U.S. GAAP and IFRS fair value measurement and disclosure requirements are described in the same way. The guidance will be effective for interim and annual periods beginning after December 15, 2011. The Company will adopt this guidance for its quarterly reporting period ending March 31, 2012. We do not expect the adoption of this guidance to have a material impact on our financial position, results of operations or cash flows.

Critical Accounting Policies

Management is required to make judgments, assumptions, and estimates that affect the amounts reported in the consolidated financial statements and the related disclosures that conform to accounting principles generally accepted in the United States. The consolidated financial statement footnotes describe the significant accounting policies and methods used in the preparation of the consolidated financial statements. Certain estimates used in the financial statements are subjective and use variables that require judgment. These include the estimates to perform goodwill and other asset impairments tests and to determine pension and postretirement benefit obligations. The Company makes other estimates in the course of accounting for unbilled revenue and the effects of regulation that are critical to the Company's financial results but that are less likely to be impacted by near term changes. Other estimates that significantly affect the Company's results, but are not necessarily critical to operations, include depreciating utility and nonutility plant, valuing reclamation liabilities, valuing derivative contracts, and estimating uncollectible accounts and coal reserves, among others. Actual results could differ from these estimates.

Goodwill

The Company performs an annual impairment analysis of its goodwill, all of which resides in the Gas Utility Services operating segment, at the beginning of each year, and more frequently if events or circumstances indicate that an impairment loss may have been incurred. Impairment tests are performed at the reporting unit level. The Company has determined its Gas Utility Services operating segment as identified in Note 13 to the consolidated financial statements to be the level at which impairment is tested as its reporting units are similar. An impairment test requires that a reporting unit's fair value be estimated. The Company used a discounted cash flow model and other market based information to estimate the fair value of its Gas Utility Services operating segment, and that estimated fair value was compared to its carrying amount, including goodwill. The estimated fair value has been in excess of the carrying amount in each of the last three years and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires significant judgment in applying a discount rate, growth assumptions, company expense allocations, and longevity of cash flows. A 100 basis point increase in the discount rate utilized to calculate the Gas Utility Services segment's fair value also would have resulted in no impairment charge.

Intercompany Allocations

Support Services

Vectren provides corporate, general, and administrative services to the Company and allocates costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs have been allocated using various allocators, including number of employees, number of customers, and/or the level of payroll, revenue contribution, and capital expenditures. Allocations are at cost. Management believes that the allocation methodology is reasonable and approximates the costs that would have been incurred had the Company secured those services on a stand-alone basis. The allocation methodology is not subject to near term changes.

Pension and Other Postretirement Obligations

Vectren satisfies the future funding requirements of its pension and other postretirement plans and the payment of benefits from general corporate assets and, as necessary, relies on Utility Holdings to support the funding of these obligations. However, Utility Holdings has no contractual funding commitment. Vectren allocates the periodic cost of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to Utility Holdings based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to Vectren Corporate operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs. Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Management believes these direct charges when combined with benefit-related corporate charges discussed in "support services" above approximate costs that would have been incurred if the Company accounted for benefit plans on a stand-alone basis.

Vectren estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other inputs, and obtains actuarial estimates to assess the future potential liability and funding requirements of pension and postretirement plans. Vectren used the following weighted average assumptions to develop 2011 periodic benefit cost: a discount rate of 5.5 percent, an expected return on plan assets of 8.0 percent, a rate of compensation increase of 3.5 percent, and an inflation assumption of 3.0 percent. Due to the low interest rates, the discount rate is 50 basis points lower from the assumption used in 2010. To estimate 2012 costs, the discount rate, expected return on plan assets, rate of compensation increase, and inflation assumption were approximately 4.80 percent, 7.75 percent, 3.5 percent, and 2.75 percent respectively, reflecting the further reductions in interest rates. Vectren's management currently estimates a pension and postretirement cost of approximately $16 million in 2012, compared to approximately $13 million in 2011, $14 million in 2010, and $15 million in 2009. Future changes in health care costs, work force demographics, interest rates, asset values or plan changes could significantly affect the estimated cost of these future benefits.

Vectren's management estimates that a 50 basis point decrease in the discount rate used to estimate retirement costs generally increases periodic benefit cost by approximately $1.5 million to $2.0 million.

Unbilled Revenues

To more closely match revenues and expenses, the Company records revenues for all gas and electricity delivered to customers but not billed at the end of the accounting period. The Company uses actual units billed during the month to allocate unbilled units by customer class. Those allocated units are multiplied by rates in effect during the month to calculate unbilled revenue at balance sheet dates.

Regulation

At each reporting date, the Company reviews current regulatory trends in the markets in which it operates. This review involves judgment and is critical in assessing the recoverability of regulatory assets as well as the ability to continue to account for its activities based on the criteria set forth in FASB guidance related to accounting for the effects of certain types of regulation. Based on the Company's current review, it believes its regulatory assets are probable of recovery. If all or part of the Company's operations cease to meet the criteria, a write off of related regulatory assets and liabilities could be required. In addition, the Company would be required to determine any impairment to the carrying value of its utility plant and other regulated assets and liabilities. In the unlikely event of a change in the current regulatory environment, such write-offs and impairment charges could be significant.

Financial Condition

Utility Holdings funds the short-term and long-term financing needs of its utility subsidiary operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' outstanding long-term and short-term borrowing arrangements are jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. The guarantees are full and unconditional and joint and several, and Utility Holdings has no subsidiaries other than the subsidiary guarantors. Information about the subsidiary guarantors as a group is included in Note 15 to the consolidated financial statements. Utility Holdings' long-term debt and short-term obligations outstanding at December 31, 2011 approximated $722 million and $243 million, respectively. Additionally, prior to Utility Holdings' formation, Indiana Gas and SIGECO funded their operations separately, and therefore, have long-term debt outstanding funded solely by their operations. SIGECO will also occasionally issue tax exempt debt to fund qualifying pollution control capital expenditures. Total Indiana Gas and SIGECO long-term debt outstanding at December 31, 2011 was $388 million.

Utility Holdings' operations have historically been the primary source for Vectren's common stock dividends.

The credit ratings of the senior unsecured debt of Utility Holdings and Indiana Gas, at December 31, 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 45-60 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 53 percent and 50 percent of long-term capitalization at December 31, 2011 and 2010, respectively. Long-term capitalization includes long-term debt, including current maturities and debt subject to tender, as well as common shareholders' equity.

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage and interest coverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 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. The Company anticipates funding future capital expenditures and dividends principally through internally generated funds. Available liquidity has been enhanced by the extension of bonus depreciation legislation. However, the resources required for capital investment remain uncertain for a variety of factors including pending legislative and regulatory initiatives involving gas pipeline modernization; and expanded EPA regulations for air, water, and fly ash. The timing and amount of such investments depends on a variety of factors, including forecasted liquidity. The Company plans to enhance its liquidity as needed by accessing the capital markets.

Long-term debt transactions completed in 2011 and 2009 include issuances by Utility Holdings totaling $250 million. In 2009, SIGECO also remarketed $41.3 million of long-term debt and completed a $22.3 million tax-exempt first mortgage bond issuance. No long-term debt transactions were completed in 2010. Utility Holdings also issued $100 million of long-term debt in February 2012. These transactions are more fully described below. (See Financing Cash Flow).

Consolidated Short-Term Borrowing Arrangements
At December 31, 2011, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2011, approximately $107 million was available. This facility is used to supplement working capital needs and also to fund capital investments and debt redemptions until financed on a long-term basis. Liquidity was increased by the $100 million Utility Holdings debt issuance in February 2012, the net proceeds of which were used to repay short-term indebtedness.

Utility Holdings' short-term credit facility was renewed in November 2011 and is available through September 2016. The maximum limit of the facility remained unchanged. The Company has historically funded the short-term borrowing needs through the commercial paper market and expects to use the short-term borrowing facility in instances where the commercial paper market is not efficient. Following is certain information regarding these short-term borrowing arrangements.

(In millions)		2011		2010		2009	
Year End							
	Balance Outstanding	$ 242.8		$ 47.0		$ 16.4	
	Weighted Average Interest Rate	0.57	%	0.41	%	0.25	%
Annual Average							
	Balance Outstanding	$ 39.6		$ 14.0		$ 29.2	
	Weighted Average Interest Rate	0.48	%	0.40	%	1.28	%
Maximum Month End Balance Outstanding		$ 242.8		$ 47.0		$ 151.1	

As of December 31, 2011, short-term borrowings included in the Consolidated Balance Sheet totaled $142.8 million, which reflects the Company's intent and ability to refinance $100 million of short-term borrowings on a long-term basis. That refinancing transaction was completed in February 2012. Throughout 2011, 2010, and most of 2009, the Company placed commercial paper without any significant issues and only had to borrow from its backup credit facility in early 2009 on a limited basis.

Proceeds from Stock Plans

Vectren may periodically issue new common shares to satisfy dividend reinvestment plan, stock option plan, and other employee benefit plan requirements and contribute those proceeds to Utility Holdings. There were no new issuances contributed to Utility Holdings in 2011 and new issuances in 2010 contributed to Utility Holdings added additional liquidity of $4.7 million.

Potential Uses of Liquidity

Planned Capital Expenditures

During 2011 and 2010, capital expenditures and other investments approximated $230 million in each period. This compares to 2009 where consolidated investments exceeded $300 million. Planned capital expenditures, including contractual purchase commitments, for the five-year period 2012 – 2016 total (in millions): $250, $270, $260, $260, and $260, respectively.

Pension and Postretirement Funding Obligations

As of December 31, 2011, Vectren's pension plan asset values were approximately 83 percent of the projected benefit obligation. Vectren's management currently estimates contributing $15 million to qualified pension plans in 2012, of which a portion may be funded by Utility Holdings. Contributions in 2013 and beyond are dependent on a variety of factors, including Vectren'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.

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2011:

	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt	$1,208.2	$-	$105.0	$-	$104.8	$13.0	$985.4
Short-term debt	142.8	142.8	-	-	-	-	-
Long-term debt interest commitments	1,056.1	67.3	65.3	62.1	61.5	56.0	743.9
Plant purchase commitments	12.0	8.4	3.6	-	-	-	-
Operating leases	2.0	0.6	0.6	0.6	0.2	-	-

Total (1)	$2,421.1	$219.1	$174.5	$62.7	$166.5	$69.0	$1,729.3

(1) The Company has other long-term liabilities that total approximately $93 million. This amount is comprised of the following: deferred compensation and share-based compensation $27 million, asset retirement obligations $34 million, postretirement obligations totaling $10 million, investment tax credits $4 million, environmental remediation $6 million, and other obligations including unrecognized tax benefits totaling $12 million. Based on the nature of these items their expected settlement dates cannot be estimated.

The Company's regulated utilities have both firm and non-firm commitments to purchase natural gas, coal, and electricity as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

Off Balance Sheet Arrangements

As of December 31, 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 the renewed credit line that expires in September of 2016. Due to the long-term nature of the credit agreement, such debt is classified as long-term at December 31, 2011. As of December 31, 2011, other than the letters of credit discussed, the Company does not have any material off balance sheet arrangements.

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 $334.3 million in 2011, compared to $277.8 million in 2010 and $356.8 million in 2009.

The $56.5 million increase in operating cash flow in 2011 compared to 2010 is primarily due to a much greater level of cash funding working capital in 2010. This increase was partially offset by higher level of employer contributions to pension and postretirement plans in 2011 compared to 2010.

The $79.0 million decrease in operating cash flow in 2010 compared to 2009 is primarily due to a decrease in operating cash flow resulting from working capital requirements of approximately $107.1 million. The change in working capital is primarily due to the timing of intercompany tax transactions and the timing of gas cost recovery mechanisms, partially offset by higher net income and non-cash charges, as well as a lower level of payments by Utility Holdings related to retirement benefits during 2010.

Tax payments in the periods presented were favorably impacted by federal legislation extending bonus depreciation and a change in the tax method for recognizing repair and maintenance activities. Federal legislation extending bonus depreciation on qualifying capital expenditures was increased to 100 percent for 2011 and continues at 50 percent for 2012. A significant portion of the Company's capital expenditures qualify for this bonus treatment.

Financing Cash Flow

Financing cash flow reflects the Company's utilization of the long-term capital markets and the current low interest rate environment. In 2011, and as impacted by the $100 million long-term debt issuance in February 2012, the Company has refinanced at lower rates approximately $346.2 million of maturing or callable long-term debt, with $250 million of new long-term debt and short-term borrowings. These lower rates began to favorably impact interest expense in the fourth quarter of 2011, and will decrease interest more significantly in 2012. In 2010 and 2009, short-term borrowings collectively decreased approximately $140 million and were generally replaced with long-term debt. The Company's operating cash flow funded 100 percent of capital expenditures and dividends in 2011, over 85 percent in 2010 and over 90 percent in 2009. Recently completed long-term financing transactions are more fully described below.

Utility Holdings 2012 Debt Issuance

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, Southern Indiana Gas and Electric Company (SIGECO), Indiana Gas Company, Inc. (Indiana Gas), and Vectren Energy Delivery of Ohio, Inc. (VEDO). The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of

December 31, 2011, the Company has reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received. The proceeds received from the issuance of the senior notes was used to refinance VUHI’s $96.2 million 5.95 percent senior notes due 2036, that were called at par and retired on Nov. 21, 2011.

Utility Holdings 2011 Debt Issuance
On November 30, 2011, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which various institutional investors purchased 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. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $148.9 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. Proceeds received from the issuance were used to partially refinance $250 million of VUHI long-term debt with an interest rate of 6.625 percent that matured Dec. 1, 2011.

Utility Holdings 2009 Debt Issuance
On April 7, 2009, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which institutional investors purchased from Utility Holdings $100 million in 6.28 percent senior unsecured notes due April 7, 2020 (2020 Notes). The 2020 Notes are guaranteed by Utility Holdings' three utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. The proceeds from the sale of the 2020 Notes, net of issuance costs, totaled approximately $99.5 million. The 2020 Notes have no sinking fund requirements and interest payments are due semi-annually. The 2020 Notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements.

SIGECO 2009 Debt Issuance
On August 19, 2009 SIGECO also completed a $22.3 million tax-exempt first mortgage bond issuance at an interest rate of 5.4 percent that is fixed through maturity. The bonds mature in 2040. The proceeds from the sale of the bonds, net of issuance costs, totaled approximately $21.3 million.

Auction Rate Securities
On March 26, 2009, SIGECO remarketed the remaining $41.3 million of its auction rate securities obligations, receiving proceeds, net of issuance costs of approximately $40.6 million. The remarketed notes have a variable rate interest rate which is reset weekly and are supported by a standby letter of credit. The notes are collateralized by SIGECO's utility plant, and $9.8 million are due in 2015 and $31.5 million are due in 2025.

Additional Capital Contributions
During the years ended December 31, 2011, 2010, and 2009, the Company has cumulatively received additional capital of $11.6 million from Vectren, funded by new share issues from Vectren's dividend reinvestment plan.

Long-Term Debt Put and Call Provisions
Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. Certain instruments can be put to the Company upon the death of the holder (death puts). During 2011, 2010, and 2009, the Company repaid approximately $0.8 million, $1.8 million, and $3.0 million, respectively, related to death puts.

On October 21, 2011, the Company notified holders of $96.2 million 5.95 percent senior notes due 2036, of its intent to call those notes. This call option was exercised at par on November 21, 2011.

Investing Cash Flow
Cash flow required for investing activities was $235.7 million in 2011, $227.2 million in 2010, and $310.3 million in 2009. Capital expenditures are the primary component of investing activities and totaled $235.3 million in 2011,

compared to $229.1 million in 2010 and $306.9 million in 2009. Increased capital expenditures in 2011 compared to 2010 primarily related to bare steel and cast iron replacement projects. The decrease in capital expenditures in 2010 compared to 2009 reflects the roughly $20 million spent in 2009 associated with the January 2009 ice storm restoration projects and less expenditures for fly ash management and generation projects.

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 fluctions.
- 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 and electricity; impacts on both gas and electric large customers; lower residential and commercial customer counts; and higher operating expenses.
- 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.
- Employee or contractor workforce factors including changes in key executives, collective bargaining agreements with union employees, aging workforce issues, work stoppages, or pandemic illness.
- Risks associated with material business transactions such as mergers, acquisitions and divestitures, including, without limitation, legal and regulatory delays; the related time and costs of implementing such transactions; integrating operations as part of these transactions; and possible failures to achieve expected gains, revenue growth and/or expense savings from such transactions.

- Costs, fines, penalties and other effects of legal and administrative proceedings, settlements, investigations, claims, including, but not limited to, such matters involving compliance with state and federal laws and interpretations of these laws.
- Changes in or additions to federal, state or local legislative requirements, such as changes in or additions to tax laws or rates, environmental laws, including laws governing greenhouse gases, mandates of sources of renewable energy, and other regulations.
- The performance of projects undertaken by Vectren's nonutility businesses and the success of efforts to invest in and develop new opportunities, including but not limited to, Vectren's coal mining, gas marketing, and energy infrastructure strategies.

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 7A. QUALITATIVE & QUANTITATIVE 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.

Commodity Price Risk

Regulated Operations
The Company's regulated operations have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs, and recovery of unaccounted for gas and other gas related expenses, also mitigate the effect volatile gas costs may have on the Company's financial condition. Although the Company's regulated operations are exposed to limited commodity price risk, volatile natural gas prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered.

Wholesale Power Marketing
The Company's wholesale power marketing activities undertake strategies to optimize electric generating capacity beyond that needed for native load. In recent years, the primary strategy involves the sale of excess generation into the MISO Day Ahead and Real-time markets. As part of these strategies, the Company may also from time to time execute energy contracts that commit the Company to purchase and sell electricity in future periods. Commodity price risk results from forward positions that commit the Company to deliver electricity. The Company mitigates price risk exposure with planned unutilized generation capability. The Company accounts for any energy contracts that are derivatives at fair value with the offset marked to market through earnings. No market sensitive derivative positions were outstanding on December 31, 2011 and 2010.

For retail sales of electricity, the Company receives the majority of its NOx and SO2 allowances at zero cost through an allocation process. Based on arrangements with regulators, wholesale operations can purchase allowances from retail operations at current market values, the value of which is distributed back to retail customers through a MISO cost recovery tracking mechanism. Wholesale operations are therefore at risk for the cost of allowances, which for the recent past have been volatile. The Company manages this risk by purchasing allowances from retail operations as needed and occasionally from other third parties in advance of usage. In the past, the Company also used derivative financial instruments to hedge this risk, but no such derivative instruments were outstanding at December 31, 2011 or 2010.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on interest expense. The Company limits this risk by allowing only an annual average of 15 percent to 25 percent of its total debt to be exposed to variable rate volatility. However, this targeted range may not always be attained during the seasonal increases in short-term borrowings. To manage this exposure, the Company may use derivative financial instruments. There were no financial derivatives outstanding at December 31. 2011.

Market risk is estimated as the potential impact resulting from fluctuations in interest rates on adjustable rate borrowing arrangements exposed to short-term interest rate volatility. During 2011 and 2010, the weighted average combined borrowings under these arrangements approximated $81 million and $55 million, respectively. At December 31, 2011, combined borrowings under these arrangements were $284 million, which excludes the impact of a $100 million long-term debt issuance occurring February 2012. As of December 31, 2010, combined borrowings under these arrangements were $88 million. Based upon average borrowing rates under these facilities during the years ended December 31, 2011 and 2010, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by $0.8 million and $0.6 million, respectively.

Other Risks

By using financial instruments to manage risk, the Company creates exposure to counter-party credit risk and market risk. The Company manages exposure to counter-party credit risk by entering into contracts with companies that can be reasonably expected to fully perform under the terms of the contract. Counter-party credit risk is monitored regularly and positions are adjusted appropriately to manage risk. Further, tools such as netting arrangements and requests for collateral are also used to manage credit risk. Market risk is the adverse effect on the value of a financial instrument that results from a change in commodity prices or interest rates. The Company attempts to manage exposure to market risk associated with commodity contracts and interest rates by establishing parameters and monitoring those parameters that limit the types and degree of market risk that may be undertaken.

The Company’s customer receivables from gas and electric sales and gas transportation services are primarily derived from residential, commercial, and industrial customers located in Indiana and west central Ohio. The Company manages credit risk associated with its receivables by continually reviewing creditworthiness and requests cash deposits or refunds cash deposits based on that review. Credit risk associated with certain investments is also managed by a review of creditworthiness and receipt of collateral. In addition, credit risk is mitigated by regulatory orders that allow recovery of all uncollectible accounts expense in Ohio and the gas cost portion of uncollectible accounts expense in Indiana based on historical experience.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Vectren Utility Holdings, Inc.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Those control procedures underlie the preparation of the consolidated balance sheets, statements of income, cash flows, and common shareholder's equity, and related footnotes contained herein.

These consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States and follow accounting policies and principles applicable to regulated public utilities. The integrity and objectivity of these consolidated financial statements, including required estimates and judgments, is the responsibility of management.

These consolidated financial statements are also subject to an evaluation of internal control over financial reporting conducted under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer. Based on that evaluation, conducted under the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, the Company concluded that its internal control over financial reporting was effective as of December 31, 2011. Management certified this in its Sarbanes Oxley Section 302 certifications, which are attached as exhibits to this 2011 Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholder and Board of Directors of Vectren Utility Holdings, Inc.:

We have audited the accompanying consolidated balance sheets of Vectren Utility Holdings, Inc. and subsidiaries (the "Company") (a wholly owned subsidiary of Vectren Corporation) as of December 31, 2011 and 2010, and the related consolidated statements of income, common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule included in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Vectren Utility Holdings, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP
Indianapolis, Indiana
March 2, 2012

VECTREN UTILITY HOLDINGS. INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31, 2011	2010
ASSETS		
Current Assets		
Cash & cash equivalents	$6.0	$2.4
Accounts receivable - less reserves of $5.9 & $4.5, respectively	95.5	106.7
Receivables due from other Vectren companies	0.2	0.1
Accrued unbilled revenues	90.8	127.8
Inventories	132.5	135.2
Recoverable fuel & natural gas costs	12.4	7.9
Prepayments & other current assets	69.3	83.4
Total current assets	406.7	463.5
Utility Plant		
Original cost	4,979.9	4,791.7
Less: accumulated depreciation & amortization	1,947.3	1,836.3
Net utility plant	3,032.6	2,955.4
Investments in unconsolidated affiliates	0.2	0.2
Other investments	31.8	31.3
Nonutility plant - net	156.6	167.2
Goodwill - net	205.0	205.0
Regulatory assets	100.0	96.9
Other assets	41.6	5.0
TOTAL ASSETS	$3,974.5	$3,924.5

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	At December 31, 2011	At December 31, 2010
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$112.9	$126.0
Accounts payable to affiliated companies	36.8	59.3
Payables to other Vectren companies	30.1	48.7
Accrued liabilities	121.0	135.9
Short-term borrowings	142.8	47.0
Current maturities of long-term debt	-	250.0
Long-term debt subject to tender	-	30.0
Total current liabilities	443.6	696.9
Long-Term Debt - Net of Current Maturities & Debt Subject to Tender	1,208.2	1,024.8
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	537.5	474.7
Regulatory liabilities	345.2	333.5
Deferred credits & other liabilities	93.4	79.2
Total deferred credits & other liabilities	976.1	887.4
Commitments & Contingencies (Notes 8 - 11)		
Common Shareholder's Equity		
Common stock (no par value)	774.6	774.6
Retained earnings	572.0	540.7
Accumulated other comprehensive income	-	0.1
Total common shareholder's equity	1,346.6	1,315.4
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	$3,974.5	$3,924.5

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2011	2010	2009
OPERATING REVENUES			
Gas utility	$819.1	$954.1	$1,066.0
Electric utility	635.9	608.0	528.6
Other	2.0	1.6	1.6
Total operating revenues	1,457.0	1,563.7	1,596.2
OPERATING EXPENSES			
Cost of gas sold	375.4	504.7	618.1
Cost of fuel & purchased power	240.4	235.0	194.3
Other operating	313.1	299.2	304.6
Depreciation & amortization	192.3	188.2	180.9
Taxes other than income taxes	54.0	59.6	60.3
Total operating expenses	1,175.2	1,286.7	1,358.2
OPERATING INCOME	281.8	277.0	238.0
Other income - net	4.3	5.4	7.8
Interest expense	80.3	81.4	79.2
INCOME BEFORE INCOME TAXES	205.8	201.0	166.6
Income taxes	82.9	77.1	59.2
NET INCOME	$122.9	$123.9	$107.4

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$122.9	$123.9	$107.4
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	192.3	188.2	180.9
Deferred income taxes & investment tax credits	64.6	71.2	76.2
Expense portion of pension & postretirement periodic benefit cost	4.6	4.1	4.1
Provision for uncollectible accounts	11.4	16.2	14.6
Other non-cash expense - net	11.0	12.4	14.0
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	36.7	(26.6)	93.1
Inventories	(15.0)	(7.3)	(43.2)
Recoverable/refundable fuel & natural gas costs	(4.5)	(30.2)	21.3
Prepayments & other current assets	28.2	(31.3)	48.1
Accounts payable, including to Vectren companies & affiliated companies	(50.3)	(6.7)	(95.9)
Accrued liabilities	(14.8)	6.4	(12.0)
Changes in noncurrent assets	(46.5)	(7.8)	1.7
Changes in noncurrent liabilities	(6.3)	(34.7)	(53.5)
Net cash flows from operating activities	334.3	277.8	356.8
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt - net of issuance costs	148.9	-	161.3
Additional capital contribution	-	4.7	6.9
Requirements for:			
Dividends to parent	(91.6)	(87.9)	(82.5)
Retirement of long-term debt	(347.0)	(1.8)	(3.0)
Other financing activities	(1.1)	-	-
Net change in short-term borrowings, including from other Vectren companies	195.8	30.6	(175.5)
Net cash flows from financing activities	(95.0)	(54.4)	(92.8)
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	0.4	3.0	0.2
Requirements for:			
Capital expenditures, excluding AFUDC equity	(235.3)	(229.1)	(306.9)
Other investments	(0.8)	(1.1)	(3.6)
Net cash flows from investing activities	(235.7)	(227.2)	(310.3)
Net change in cash & cash equivalents	3.6	(3.8)	(46.3)
Cash & cash equivalents at beginning of period	2.4	6.2	52.5
Cash & cash equivalents at end of period	$6.0	$2.4	$6.2

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(In millions)

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at January 1, 2009	$763.0	$479.8	$ 0.1	$1,242.9
Comprehensive income:				
Net income & total comprehensive income		107.4		107.4
Common stock:				
Additional capital contribution	6.9			6.9
Dividends		(82.5)		(82.5)
Balance at December 31, 2009	769.9	504.7	0.1	1,274.7
Comprehensive income:				
Net income & total comprehensive income		123.9		123.9
Common stock:				
Additional capital contribution	4.7			4.7
Dividends		(87.9)		(87.9)
Balance at December 31, 2010	774.6	540.7	0.1	1,315.4
Comprehensive income:				
Net income		122.9		122.9
Cash flow hedge				
Reclassification to net income			(0.1)	(0.1)
Total comprehensive income				122.8
Common stock:				
Dividends		(91.6)		(91.6)
Balance at December 31, 2011	$774.6	$572.0	$ -	$1,346.6

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

VECTREN UTILITY HOLDINGS, INC. AND SUBSIDIARY COMPANIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization & Nature of Operations

Vectren Utility Holdings, Inc. (the Company or Utility Holdings), an Indiana corporation, was formed on March 31, 2000, to serve as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas or Vectren North), Southern Indiana Gas and Electric Company (SIGECO or Vectren South), and Vectren Energy Delivery of Ohio, Inc. (VEDO). Utility Holdings also has other assets that provide information technology and other services to the three utilities. Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and was organized on June 10, 1999. Both Vectren and Utility Holdings are holding companies as defined by the Energy Policy Act of 2005 (Energy Act).

Indiana Gas provides energy delivery services to approximately 563,000 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. VEDO provides energy delivery services to over 310,000 natural gas customers located near Dayton in west central Ohio.

2. Summary of Significant Accounting Policies

In applying its accounting policies, the Company makes judgments, assumptions, and estimates that affect the amounts reported in these consolidated financial statements and related footnotes. Examples of transactions for which estimation techniques are used include valuing pension and postretirement benefit obligations, deferred tax obligations, unbilled revenue, uncollectible accounts, regulatory assets and liabilities, reclamation liabilities, and derivatives and other financial instruments. Estimates also impact the depreciation of utility and nonutility plant and the testing of goodwill and other assets for impairment. Recorded estimates are revised when better information becomes available or when actual amounts can be determined. Actual results could differ from current estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries, after elimination of significant intercompany transactions.

Subsequent Events Review

Management performs a review of subsequent events for any events occurring after the balance sheet date but prior to the date the financial statements are issued.

Cash & Cash Equivalents

All highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash and cash equivalents are stated at cost plus accrued interest to approximate fair value.

Allowance for Uncollectible Accounts

The Company maintains allowances for uncollectible accounts for estimated losses resulting from the inability of its customers to make required payments. The Company estimates the allowance for uncollectible accounts based on a variety of factors including the length of time receivables are past due, the financial health of its customers, unusual macroeconomic conditions, and historical experience. If the financial condition of its customers deteriorates or other circumstances occur that result in an impairment of customers' ability to make payments, the Company records additional allowances as needed.

Inventories

In most circumstances, the Company's inventory components are recorded using an average cost method; however, natural gas in storage at the Company's Indiana utilities is recorded using the Last In – First Out (LIFO) method. Inventory related to the Company's regulated operations is valued at historical cost consistent with ratemaking treatment. Materials and supplies are recorded as inventory when purchased and subsequently charged to expense or capitalized to plant when installed.

Property, Plant & Equipment

Both the Company's Utility Plant and Nonutility Plant is stated at historical cost, inclusive of financing costs and direct and indirect construction costs, less accumulated depreciation and when necessary, impairment charges. The cost of renewals and betterments that extend the useful life are capitalized. Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred.

Utility Plant & Related Depreciation

Both the IURC and PUCO allow the Company's utilities to capitalize financing costs associated with Utility Plant based on a computed interest cost and a designated cost of equity funds. These financing costs are commonly referred to as AFUDC and are capitalized for ratemaking purposes and for financial reporting purposes instead of amounts that would otherwise be capitalized when acquiring nonutility plant. The Company reports both the debt and equity components of AFUDC in Other income – net in the Consolidated Statements of Income.

When property that represents a retirement unit is replaced or removed, the remaining historical value of such property is charged to Utility plant, with an offsetting charge to Accumulated depreciation, resulting in no gain or loss. Costs to dismantle and remove retired property are recovered through the depreciation rates as determined by the IURC and PUCO.

The Company's portion of jointly-owned Utility Plant, along with that plant's related operating expenses, is presented in these financial statements in proportion to the ownership percentage.

Nonutility Plant & Related Depreciation

The depreciation of Nonutility Plant is charged against income over its estimated useful life, using the straight-line method of depreciation. When nonutility property is retired, or otherwise disposed of, the asset and accumulated depreciation are removed, and the resulting gain or loss is reflected in income, typically impacting operating expenses.

Impairment Reviews

Property, plant and equipment along with other long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This impairment review involves the comparison of an asset's (or group of assets') carrying value to the estimated future cash flows the asset (or asset group) is expected to generate over a remaining life. If this evaluation were to conclude that the carrying value is impaired, an impairment charge would be recorded based on the difference between the carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations. There were no impairments related to property, plant and equipment during the periods presented.

Goodwill

Goodwill recorded on the Consolidated Balance Sheets results from business acquisitions in the Gas Utility Services operating segment and is based on a fair value allocation of the businesses' purchase price at the time of acquisition. Goodwill is charged to expense only when it is impaired. The Company tests its goodwill for impairment at an operating segment level because the components within the segment are similar. These tests are performed at least annually and that test is performed at the beginning of each year. Impairment reviews consist of a comparison of fair value to the carrying amount. If the fair value is less than the carrying amount, an impairment loss is recognized in operations. No goodwill impairments have been recorded during the periods presented.

Regulation

Retail public utility operations affecting Indiana customers are subject to regulation by the IURC, and retail public utility operations affecting Ohio customers are subject to regulation by the PUCO. The Company's accounting policies give recognition to the ratemaking and accounting practices authorized by these agencies.

Refundable or Recoverable Gas Costs & Cost of Fuel & Purchased Power

All metered gas rates contain a gas cost adjustment clause that allows the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel. The net energy cost of purchased power, subject to a variable benchmark based on NYMEX natural gas prices, is also recovered through regulatory proceedings. The Company records any under-or-over-recovery resulting from gas and fuel adjustment clauses each month in revenues. A corresponding asset or liability is recorded until the under or over-recovery is billed or refunded to utility customers. The cost of gas sold is charged to operating expense as delivered to customers, and the cost of fuel and purchased power for electric generation is charged to operating expense when consumed.

Regulatory Assets & Liabilities
Regulatory assets represent probable future revenues associated with certain incurred costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable expenditures by the Company for removal costs or future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. The Company continually assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to recognize new regulatory assets and liabilities associated with its regulated utility operations. Given the current regulatory environment in its jurisdictions, the Company believes such accounting is appropriate.

The Company collects an estimated cost of removal of its utility plant through depreciation rates established in regulatory proceedings. The Company records amounts expensed in advance of payments as a Regulatory liability because the liability does not meet the threshold of an asset retirement obligation.

Asset Retirement Obligations
A portion of removal costs related to interim retirements of gas utility pipeline and utility poles and certain asbestos-related issues meet the definition of an asset retirement obligation (ARO). The Company records the fair value of a liability for a legal ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. The liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, regulatory assets and liabilities result when accretion and amortization is adjusted to match rates established by regulators and any gain or loss is subject to deferral.

Energy Contracts & Derivatives
The Company will periodically execute derivative contracts in the normal course of operations while buying and selling commodities to be used in operations, optimizing its generation assets, and managing risk. A derivative is recognized on the balance sheet as an asset or liability measured at its fair market value and the change in the derivative's fair market value is recognized currently in earnings unless specific hedge criteria are met.

When an energy contract, that is a derivative, is designated and documented as a normal purchase or normal sale (NPNS), it is exempted from mark-to-market accounting. Most energy contracts executed by the Company are subject to the NPNS exclusion or are not considered derivatives. Such energy contracts include Real Time and Day Ahead purchase and sale contracts with the MISO, natural gas purchases from ProLiance and others, and wind farm and other electric generating contracts.

When the Company engages in energy contracts and financial contracts that are derivatives and are not subject to the NPNS or other exclusions, such contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and on when the contracts are expected to be settled. Contracts and any associated collateral with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. The offset resulting from carrying the derivative at fair value on the balance sheet is charged to earnings unless it qualifies as a hedge or is subject to regulatory accounting treatment. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between the derivative contract and underlying risks as well as its risk management objectives and anticipated effectiveness. When the hedging relationship is highly effective, derivatives are designated as hedges. The market value of the effective portion of the hedge is marked to market in Accumulated other comprehensive income for cash flow hedges. Ineffective portions of hedging arrangements are marked to market through earnings. For fair value hedges, both the derivative and the underlying hedged item are marked to market through earnings. The offset to contracts affected by regulatory accounting treatment are marked to market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources. The Company rarely enters into contracts that have a significant impact to the financial statements where internal models are used to calculate fair value. As of and for the periods presented, related derivative activity is not material to these financial statements.

Revenues
Revenues are recorded as products and services are delivered to customers. To more closely match revenues and expenses, the Company records revenues for all gas and electricity delivered to customers but not billed at the end of the accounting period in Accrued Unbilled Revenues.

MISO Transactions
With the IURC's approval, the Company is a member of the MISO, a FERC approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midwest and maintains operational control over the Company's electric transmission facilities as well as that of other Midwest utilities. The Company is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

MISO-related purchase and sale transactions are recorded using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded in Cost of fuel & purchased power and net sales in a single hour are recorded in Electric utility revenues. On occasion, prior period transactions are resettled outside the routine process due to a change in MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

The Company also receives transmission revenue that results from other members' use of the Company's transmission system. These revenues are also included in Electric utility revenues. Generally, these transmission revenues along with costs charged by the MISO are considered components of base rates and any variance from that included in base rates is recovered from / refunded to retail customers through tracking mechanisms.

Excise & 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 $29.0 million in 2011, $33.6 million in 2010, and $36.2 million in 2009. Expense associated with excise and utility receipts taxes are recorded as a component of Taxes other than income taxes.

Fair Value Measurements
Certain assets and liabilities are valued and/or disclosed at fair value. Nonfinancial assets and liabilities include the initial measurement of an asset retirement obligation or the use of fair value in goodwill, intangible assets and long-lived assets impairment tests. FASB guidance provides the framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are described as follows:

Level 1	Inputs to the valuation methodology are unadjusted quoted prices for identical assets or liabilities in active markets.
Level 2	Inputs to the valuation methodology include · quoted prices for similar assets or liabilities in active markets; · quoted prices for identical or similar assets or liabilities in inactive markets; · inputs other than quoted prices that are observable for the asset or liability; · inputs that are derived principally from or corroborated by observable market data by correlation or other means

	If the asset or liability has a specified (contractual) term, the Level 2 input must be observable for substantially the full term of the asset or liability.
Level 3	Inputs to the valuation methodology are unobservable and significant to the fair value measurement.

The asset's or liability's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

Earnings Per Share
Earnings per share are not presented as Utility Holdings' common stock is wholly owned by Vectren.

Other Significant Policies
Included elsewhere in these notes are significant accounting policies related to intercompany allocations and income taxes (Note 5).

3. Utility & Nonutility Plant

The original cost of Utility Plant, together with depreciation rates expressed as a percentage of original cost, follows:

	At and For the Year Ended December 31,			
(In millions)	2011		2010	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$2,516.8	3.5 %	$2,410.2	3.6 %
Electric utility plant	2,316.8	3.3 %	2,258.6	3.4 %
Common utility plant	51.6	2.9 %	49.7	3.1 %
Construction work in progress	94.7	-	73.2	-
Total original cost	$4,979.9		$4,791.7	

SIGECO and Alcoa Generating Corporation (AGC), a subsidiary of ALCOA, own the 300 MW Unit 4 at the Warrick Power Plant as tenants in common. SIGECO's share of the cost of this unit at December 31, 2011, is $182.6 million with accumulated depreciation totaling $70.3 million. AGC and SIGECO also share equally in the cost of operation and output of the unit. SIGECO's share of operating costs is included in Other operating expenses in the Consolidated Statements of Income.

Nonutility plant, net of accumulated depreciation and amortization follows:

	At December 31,	
(In millions)	2011	2010
Computer hardware & software	$101.3	$112.9
Land & buildings	40.0	39.0
All other	15.3	15.3
Nonutility plant - net	$156.6	$167.2

Nonutility plant is presented net of accumulated depreciation and amortization totaling $188.8 million and $184.0 million as of December 31, 2011 and 2010, respectively. For the years ended December 31, 2011, 2010, and 2009, the Company capitalized interest totaling $0.3 million, $0.2 million, and $0.2 million, respectively, on nonutility plant construction projects.

4. Regulatory Assets & Liabilities

Regulatory Assets

Regulatory assets consist of the following:

(In millions)	At December 31, 2011	2010
Future amounts recoverable from ratepayers related to:		
Deferred income taxes (See Notes 5 & 9)	$ 1.3	$ 19.2
Asset retirement obligations & other	2.3	2.1
	3.6	21.3
Amounts deferred for future recovery related to:		
Deferred coal costs (See Note 11)	17.7	-
Cost recovery riders & other	6.4	2.8
	24.1	2.8
Amounts currently recovered in customer rates related to:		
Unamortized debt issue costs & hedging proceeds	34.3	35.7
Demand side management programs	6.3	9.5
Indiana authorized trackers	24.3	17.3
Ohio authorized trackers	1.0	2.0
Premiums paid to reacquire debt	3.3	3.8
Other base rate recoveries	3.1	4.5
	72.3	72.8
Total regulatory assets	$ 100.0	$ 96.9

Of the $72.3 million currently being recovered in customer rates, $6.3 million that is associated with demand side management programs is earning a return. The weighted average recovery period of regulatory assets currently being recovered is 17 years. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Regulatory Liabilities

At December 31, 2011 and 2010, the Company has $345.2 million and $333.5 million, respectively, in Regulatory liabilities. Of these amounts, $320.9 million and $307.5 million relate to cost of removal obligations. The remaining amounts primarily relate to timing differences associated with asset retirement obligations and deferred financing costs.

5. Transactions with Other Vectren Companies and Affiliates

Vectren Fuels, Inc.

Vectren Fuels, Inc., a wholly owned subsidiary of Vectren, owns coal mines from which SIGECO purchases coal used for electric generation. The price of coal that is charged by Vectren Fuels to SIGECO is priced consistent with contracts reviewed by the OUCC and on file with IURC. Amounts purchased for the years ended December 31, 2011, 2010 and 2009, totaled $144.1 million, $152.4 million, and $152.9 million, respectively. Amounts owed to Vectren Fuels at December 31, 2011 and 2010 are included in Payables to other Vectren companies.

Miller Pipeline, LLC

Miller Pipeline, LLC (Miller), a wholly owned subsidiary of Vectren, performs natural gas and water distribution, transmission, and construction repair and rehabilitation primarily in the Midwest and the repair and rehabilitation of gas, water, and wastewater facilities nationwide. Miller's customers include Utility Holdings' utilities. Fees incurred by Utility Holdings and its subsidiaries totaled $43.1 million in 2011, $24.4 million in 2010, and $34.7 million in

2009. Amounts owed to Miller at December 31, 2011 and 2010 are included in Payables to other Vectren companies.

Vectren Source

Vectren Source, a former wholly owned and nonutility subsidiary of Vectren that was sold on December 31, 2011, provided natural gas and other related products and services in the Midwest and Northeast United States to approximately 283,000 residential and commercial customers. This customer base reflected approximately 143,000 customers in VEDO's 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 the merchant function process. Since January 2010, Vectren Source has sold gas commodity directly to customers in VEDO's service territory and VEDO purchases receivables from Vectren Source to include those sales in one customer bill similar to the receivables purchased from Vectren Source related to customers that voluntarily chose Vectren Source as their supplier. Total receivables purchased from Vectren Source in the twelve months ended December 31, 2011 and 2010 totaled $66.5 million and $54.4 million, respectively.

As part of VEDO's initial phase of exiting the merchant function which ended on March 31, 2010, the Company purchased natural gas from Vectren Source. Such purchases totaled $3.0 million in 2011, $14.9 million in 2010, and $27.0 million in 2009, which represented approximately 1 percent, 2 percent, and 4 percent of the Company's total gas purchased during 2011, 2010, and 2009 respectively. Amounts charged by Vectren Source for gas supply services are comprised of the monthly NYMEX settlement price plus a fixed adder, as authorized by the PUCO.

ProLiance Holdings, LLC (ProLiance)
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 the Company's Indiana utilities as well as Citizens' utilities. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services. 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.

Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2011, 2010 and 2009 totaled $375.7 million, $426.9 million, and $436.2 million, respectively. Amounts owed to ProLiance at December 31, 2011 and 2010, for those purchases were $36.8 million and $59.3 million, respectively, and are included in Accounts payable to affiliated companies in the Consolidated Balance Sheets. The Company purchased approximately 97 percent of its gas through ProLiance in 2011, 86 percent in 2010, and 76 percent in 2009. The increased percentages purchased from ProLiance in 2010 and 2011 reflect VEDO's exit the merchant function, as discussed above, whereby VEDO no longer purchases natural gas. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

Support Services & Purchases
Vectren provides corporate and general and administrative services to the Company and allocates costs to the Company, including costs for share-based compensation and for pension and other postretirement benefits that are not directly charged to subsidiaries. These costs have been allocated using various allocators, including number of employees, number of customers and/or the level of payroll, revenue contribution and capital expenditures. Allocations are at cost. Utility Holdings received corporate allocations totaling $46.1 million, $47.8 million, and $48.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Retirement Plans & Other Postretirement Benefits
At December 31, 2011, Vectren maintains three qualified defined benefit pension plans (Vectren Corporation Non-Bargaining Retirement Plan, The Indiana Gas Company, Inc. Bargaining Unit Retirement Plan, Pension Plan for Hourly Employees of Southern Indiana Gas and Electric Company), a nonqualified supplemental executive retirement plan, and three other postretirement benefit plans. The defined benefit pension and other postretirement benefit plans, which cover the Company's 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. Utility Holdings and its subsidiaries comprise the vast majority of the participants and retirees covered by these plans. In September 2011, the FASB issued new accounting guidance that requires enhanced disclosures regarding an employer's participation in defined benefit pension plans accounted for as "multiemployer" plans. The Company has adopted this guidance for the Company's 2011 financial statements as required which resulted in expanded disclosures.

Vectren satisfies the future funding requirements and the payment of benefits from general corporate assets and, as necessary, relies on Utility Holdings to support the funding of these obligations. However, Utility Holdings has no contractual funding commitment. For the years ended December 31, 2011, 2010 and 2009, Utility Holdings contributed approximately $33.4 million, $11.6 million, and $29.1 million, respectively, to Vectren's defined benefit pension plans. Such contributions are made to Vectren in total and are not plan specific. The combined funded status of Vectren's plans was 83 percent at both December 31, 2011 and 2010.

Vectren allocates the periodic cost of its retirement plans calculated pursuant to US GAAP to its subsidiaries. Periodic cost, comprised of service cost and interest on that service cost, is directly charged to Utility Holdings based on labor at each measurement date and that cost is charged to operating expense and capital projects, using labor charges as the allocation method. For the years ended December 31, 2011, 2010 and 2009, costs totaling $6.6 million, $5.9 million and $5.9 million, respectively, were directly charged to Utility Holdings. Other components of periodic costs (such as interest cost, asset returns, and amortizations) and the service cost related to Vectren Corporate operations are charged to subsidiaries through the allocation process discussed above. Any difference between funding requirements and allocated periodic costs is recognized as an asset or liability until reflected in periodic costs.

Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. The allocation methodology is consistent with FASB guidance related to "multiemployer" benefit accounting. As of December 31, 2011 and 2010, $10.2 million and $0.7 million, respectively, is included in Deferred credits & other liabilities and represents costs directly charged to the Company that is yet to be funded to Vectren. As impacted by increased funding of pension plans in 2011, the Company has $37.8 million included in Other Assets representing defined benefit funding by the Company that is yet to be reflected in costs.

Share-Based Incentive Plans & Deferred Compensation Plans

Utility Holdings does not have share-based compensation plans separate from Vectren. The Company recognizes its allocated portion of expenses related to share-based incentive plans and deferred compensation plans in accordance with FASB guidance and to the extent these awards are expected to be settled in cash that liability is pushed down to Utility Holdings. As of December 31, 2011 and 2010, $27.1 million and $24.6 million, respectively, is included in Deferred credits & other liabilities and represents obligations that are yet to be funded to Vectren.

Income Taxes

Vectren files a consolidated federal income tax return. Pursuant to a subsidiary tax sharing agreement and for financial reporting purposes, Utility Holdings' current and deferred tax expense is computed on a separate company basis. Current taxes payable/receivable are settled with Vectren in cash.

Deferred income taxes are provided for temporary differences between the tax basis (adjusted for related unrecognized tax benefits, if any) of an asset or liability and its reported amount in the financial statements. Deferred tax assets and liabilities are computed based on the currently-enacted statutory income tax rates that are expected to be applicable when the temporary differences are scheduled to reverse. The Company's rate-regulated utilities recognize regulatory liabilities for deferred taxes provided in excess of the current statutory tax rate and regulatory assets for deferred taxes provided at rates less than the current statutory tax rate. Such tax-related regulatory assets and liabilities are reported at the revenue requirement level and amortized to income as the related temporary differences reverse, generally over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets unless it is more likely than not that the deferred tax assets will be realized.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more-likely-than-not recognition threshold is satisfied and measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company reports interest and penalties associated with unrecognized tax benefits within Income taxes in the Consolidated Statements of Income and reports tax liabilities related to unrecognized tax benefits as part of Deferred credits & other liabilities.

Investment tax credits (ITCs) are deferred and amortized to income over the approximate lives of the related property in accordance with the regulatory treatment. Production tax credits (PTCs) are recognized as energy is generated and sold based on a per kilowatt hour rate prescribed in applicable federal and state statutes.

The components of income tax expense and utilization of investment tax credits follow:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Current:			
Federal	$ 10.4	$ (0.7)	$ (18.2)
State	7.9	6.6	1.2
Total current taxes	18.3	5.9	(17.0)
Deferred:			
Federal	58.6	67.6	70.3
State	6.6	4.4	7.0
Total deferred taxes	65.2	72.0	77.3
Amortization of investment tax credits	(0.6)	(0.8)	(1.1)
Total income tax expense	$ 82.9	$ 77.1	$ 59.2

A reconciliation of the federal statutory rate to the effective income tax rate follows:

	Year Ended December 31,		
	2011	2010	2009
Statutory rate	35.0 %	35.0 %	35.0 %
State and local taxes-net of federal benefit	3.9	3.8	2.9
Amortization of investment tax credit	(0.3)	(0.4)	(0.6)
Tax law changes and other adjustments to income tax accruals	0.6	-	(1.7)
All other - net	1.1	-	-
Effective tax rate	40.3 %	38.4 %	35.6 %

Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2011	2010
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 551.8	$ 508.8
Regulatory assets recoverable through future rates	25.1	24.9
Alternative minimum tax carryforward	(35.0)	(48.6)
Employee benefit obligations	11.3	-
Regulatory liabilities to be settled through future rates	(17.2)	(9.5)
Other – net	1.5	(0.9)
Net noncurrent deferred tax liability	537.5	474.7
Current deferred tax liabilities (assets):		
Deferred fuel costs - net	6.0	4.9
Alternative minimum tax carryforward	(15.6)	(0.8)
Demand side management programs	0.7	2.5
Other – net	(5.4)	(6.2)
Net current deferred tax liability (asset)	(14.3)	0.4
Net deferred tax liability	$ 523.2	$ 475.1

At December 31, 2011 and 2010, investment tax credits totaling $4.4 million and $5.0 million, respectively, are included in Deferred credits & other liabilities. At December 31, 2011, the Company has alternative minimum tax carryforwards of $50.6 million, which do not expire.

Uncertain Tax Positions

Following is a roll forward of the total amount of unrecognized tax benefits for the three years ended December 31, 2011 and 2010:

(In millions)	2011	2010	2009
Unrecognized tax benefits at January 1	$11.8	$9.5	$0.5
Gross increases - tax positions in prior periods	3.3	1.5	1.0
Gross decreases - tax positions in prior periods	(4.4)	(0.2)	(1.9)
Gross increases - current period tax positions	0.6	1.0	9.0
Settlements	(0.3)	-	0.3
Lapse of statute of limitations	-	-	0.6
Unrecognized tax benefits at December 31	$11.0	$11.8	$9.5

Of the change in unrecognized tax benefits during 2011, 2010, and 2009, almost none impacted the effective rate. The amount of unrecognized tax benefits, which if recognized, that would impact the effective tax rate was $0.2 million at December 31, 2009, and almost none at December 31, 2011 and 2010. As of December 31, 2011, the unrecognized tax benefit relates to tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority. Thus, it is not expected that any changes to these tax positions would have a significant impact on earnings.

The Company recognized expense related to interest and penalties totaling approximately $0.4 million in 2011, $0.3 million in 2010, and $0.1 million in 2009. The Company had approximately $0.9 million and $0.5 million for the payment of interest and penalties accrued as of December 31, 2011 and 2010, respectively.

The net liability on the Consolidated Balance Sheet for unrecognized tax benefits inclusive of interest, penalties and net of secondary impacts which are a component of the Deferred income taxes and are benefits, totaled $10.8 million and $11.3 million, respectively, at December 31, 2011 and 2010.

Utility Holdings does not file federal or state income tax returns separate from those filed by its parent, Vectren Corporation. Vectren files a consolidated U.S. federal income tax return, and Vectren and/or certain of its subsidiaries file income tax returns in various states. The Internal Revenue Service (IRS) has concluded examinations of Vectren's U.S. federal income tax returns for tax years through December 31, 2005. Tax years 2006 and 2008 are currently under IRS exam. The primary focus of the IRS examination is certain repairs and maintenance deductions, an area of particular focus by the IRS throughout the utility industry. Vectren received Notices of Assessment from the IRS related to these deductions. Vectren responded to the assessments in January 2012 and continues to follow industry activities in this area. However, in the event the IRS assessments related to these deductions are upheld, any impact is not expected to be material to the Company's results of operations or financial condition. Further, the Company doesn't expect any changes to this liability for unrecognized income tax benefits within the next 12 months that would significantly impact the Company's results of operations or financial condition. The State of Indiana, Vectren's primary state tax jurisdiction, has conducted examinations of state income tax returns for tax years through December 31, 2007. The statutes of limitations for assessment of federal income tax have expired with respect to tax years through 2005 and through 2007 for Indiana income tax.

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6. Borrowing Arrangements

Long-Term Debt

Long-term senior unsecured obligations and first mortgage bonds outstanding by subsidiary follow:

(In millions)	At December 31, 2011	2010
Utility Holdings		
Fixed Rate Senior Unsecured Notes		
2011, 6.625%	$ -	$ 250.0
2013, 5.25%	100.0	100.0
2015, 5.45%	75.0	75.0
2018, 5.75%	100.0	100.0
2020, 6.28%	100.0	100.0
2021, 4.67%	55.0	-
2026, 5.02%	60.0	-
2035, 6.10%	75.0	75.0
2036, 5.95%	-	96.7
2039, 6.25%	121.6	121.9
2041, 5.99%	35.0	-
Total Utility Holdings	721.6	918.6
SIGECO		
First Mortgage Bonds		
2015, 1985 Pollution Control Series A, current adjustable rate 0.10%,		
tax exempt, 2011 weighted average: 0.19%	9.8	9.8
2016, 1986 Series, 8.875%	13.0	13.0
2020, 1998 Pollution Control Series B, 4.50%, tax exempt	4.6	4.6
2023, 1993 Environmental Improvement Series B, 5.15%, tax exempt	22.6	22.6
2024, 2000 Environmental Improvement Series A, 4.65%, tax exempt	22.5	22.5
2025, 1998 Pollution Control Series A, current adjustable rate 0.10%,		
tax exempt, 2011 weighted average: 0.19%	31.5	31.5
2029, 1999 Senior Notes, 6.72%	80.0	80.0
2030, 1998 Pollution Control Series B, 5.00%, tax exempt	22.0	22.0
2030, 1998 Pollution Control Series C, 5.35%, tax exempt	22.2	22.2
2040, 2009 Environmental Improvement Series, 5.40%, tax exempt	22.3	22.3
2041, 2007 Pollution Control Series, 5.45%, tax exempt	17.0	17.0

Total SIGECO	267.5	267.5
Indiana Gas		
Senior Unsecured Notes		
2013, Series E, 6.69%	5.0	5.0
2015, Series E, 7.15%	5.0	5.0
2015, Series E, 6.69%	5.0	5.0
2015, Series E, 6.69%	10.0	10.0
2025, Series E, 6.53%	10.0	10.0
2027, Series E, 6.42%	5.0	5.0
2027, Series E, 6.68%	1.0	1.0
2027, Series F, 6.34%	20.0	20.0
2028, Series F, 6.36%	10.0	10.0
2028, Series F, 6.55%	20.0	20.0
2029, Series G, 7.08%	30.0	30.0
Total Indiana Gas	121.0	121.0
Total long-term debt outstanding	1,110.1	1,307.1
Current maturities of long-term debt	-	(250.0)
Short-term borrowings refinanced in 2012	100.0	-
Debt subject to tender	-	(30.0)
Unamortized debt premium & discount - net	(1.9)	(2.3)
Total long-term debt-net	$ 1,208.2	$ 1,024.8

Utility Holdings 2012 Debt Issuance

On February 1, 2012, Utility Holdings issued $100 million of senior unsecured notes at an interest rate of 5.00 percent per annum and with a maturity date of February 3, 2042. The notes were sold to various institutional investors pursuant to a private placement note purchase agreement executed in November 2011 with a delayed draw feature. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $99.5 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements. As of December 31, 2011, the Company has reclassified $100 million of short-term borrowings as long-term debt to reflect those borrowings were refinanced with the proceeds received.

Utility Holdings 2011 Debt Issuance

On November 30, 2011, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which various institutional investors purchased 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. These senior notes are unsecured and jointly and severally guaranteed by Utility Holdings' regulated utility subsidiaries, SIGECO, Indiana Gas, and VEDO. The proceeds from the sale of the notes, net of issuance costs, totaled approximately $148.9 million. These notes have no sinking fund requirements and interest payments are due semi-annually. These notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements.

Utility Holdings 2009 Debt Issuance

On April 7, 2009, Utility Holdings closed a financing under a private placement note purchase agreement pursuant to which institutional investors purchased from Utility Holdings $100 million in 6.28 percent senior unsecured notes due April 7, 2020 (2020 Notes). The 2020 Notes are guaranteed by Utility Holdings' three utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. The proceeds from the sale of the 2020 Notes, net of issuance costs, totaled approximately $99.5 million. The 2020 Notes have no sinking fund requirements and interest payments are due semi-annually. The 2020 Notes contain customary representations, warranties and covenants, including a leverage covenant consistent with leverage covenants contained in other Utility Holdings' borrowing arrangements.

SIGECO 2009 Debt Issuance

On August 19, 2009 SIGECO also completed a $22.3 million tax-exempt first mortgage bond issuance at an interest rate of 5.4 percent that is fixed through maturity. The bonds mature in 2040. The proceeds from the sale of the bonds, net of issuance costs, totaled approximately $21.3 million.

Auction Rate Securities

On March 26, 2009, SIGECO remarketed the remaining $41.3 million of its auction rate securities obligations, receiving proceeds, net of issuance costs of approximately $40.6 million. The remarketed notes have a variable rate interest rate which is reset weekly and are supported by a standby letter of credit. The notes are collateralized by SIGECO's utility plant, and $9.8 million are due in 2015 and $31.5 million are due in 2025.

Long-Term Debt Puts & Calls

Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. Certain instruments can be put to the Company upon the death of the holder (death puts). During 2011, 2010, and 2009, the Company repaid approximately $0.8 million, $1.8 million, and $3.0 million, respectively, related to death puts.

On October 21, 2011, the Company notified holders of Utility Holdings $96.2 million 5.95 percent senior notes due 2036, of its intent to call those notes. This call option was exercised at par on November 21, 2011.

Future Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1 percent of the greatest amount of bonds outstanding under the Mortgage Indenture. This requirement may be satisfied by certification to the Trustee of unfunded property additions in the prescribed amount as provided in the Mortgage Indenture. SIGECO intends to meet the 2011 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2010 is excluded from Current liabilities in the Consolidated Balance Sheets. At December 31, 2011, $1.3 billion of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO’s gross utility plant balance subject to the Mortgage Indenture approximated $2.7 billion at December 31, 2011.

Consolidated maturities of long-term debt during the years following 2011 (in millions) are zero in 2012, $105.0 in 2013, zero in 2014, $104.8 in 2015, and $13.0 in 2016, and $985.4 thereafter.

Debt Guarantees

Utility Holdings' currently outstanding long-term and short-term debt is jointly and severally guaranteed by Indiana Gas, SIGECO, and VEDO. Utility Holdings' long-term debt and short-term debt outstanding at December 31, 2011, totaled $722 million and $243 million, respectively.

Covenants

Both long-term and short-term borrowing arrangements contain customary default provisions; restrictions on liens, sale-leaseback transactions, mergers or consolidations, and sales of assets; and restrictions on leverage and interest coverage, among other restrictions. Multiple debt agreements contain a covenant that the ratio of consolidated total debt to consolidated total capitalization will not exceed 65 percent. As of December 31, 2011, the Company was in compliance with all debt covenants.

Short-Term Borrowings

At December 31, 2011, the Company has $350 million of short-term borrowing capacity. As reduced by borrowings outstanding at December 31, 2011, approximately $107 million was available. This short-term borrowing facility was amended effective November 10, 2011 to extend its maturity date from 2013 to 2016 at current market rates. The $350 million of capacity remains unchanged. The Company has historically funded the short-term borrowing needs of Utility Holdings' operations through the commercial paper market and expects to use the Utility Holdings short-term borrowing facility in instances where the commercial paper market is not efficient.

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

(In millions)		2011	2010	2009
Year End				
	Balance Outstanding	$ 242.8	$ 47.0	$ 16.4
	Weighted Average Interest Rate	0.57 %	0.41 %	0.25 %
Annual Average				
	Balance Outstanding	$ 39.6	$ 14.0	$ 29.2
	Weighted Average Interest Rate	0.48 %	0.40 %	1.28 %
Maximum Month End Balance Outstanding		$ 242.8	$ 47.0	$ 151.1

Throughout 2011, 2010, and most of 2009, the Company has placed commercial paper without any significant issues and only had to borrow from its backup credit facility in early 2009 on a limited basis. As noted above, $100 million of the outstanding borrowings are presented as long-term at December 31, 2011.

7. Common Shareholder's Equity

During the years ended December 31, 2011, 2010, and 2009, the Company has cumulatively received additional capital of $11.6 million from Vectren which was funded by new share issues from Vectren's dividend reinvestment plan and other stock plans.

8. Commitments & Contingencies

Commitments

Future minimum lease payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year during the five years following 2011 and thereafter (in millions) are $0.6 in 2012, $0.6 in 2013, $0.6 in 2014, $0.2 in 2015, and zero in 2016 and thereafter. Total lease expense (in millions) was $0.6 in 2011, $0.7 in 2010, and $0.9 in 2009. Firm purchase commitments for utility plant total $8.4 in 2012, $3.6 million in 2013, and zero in 2014 and thereafter.

The Company's regulated utilities have both firm and non-firm commitments to purchase natural gas, coal, and electricity as well as certain transportation and storage rights. Costs arising from these commitments, while significant, are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms. Because of the pass through nature of these costs, they have not been included in the listing of contractual obligations.

Legal 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.

9. Legislative Matters

Pipeline Safety Law

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

The Company continues to study the impact of the new law and potential new regulations associated with its implementation. At this time, compliance costs and other effects associated with the increased pipeline safety regulations remain uncertain. However, the new law is expected to result in further investment in pipeline inspections, and where necessary, additional modernization of pipeline infrastructure; and therefore, result in both increased levels of operating expenses and capital expenditures associated with the Company's natural gas distribution businesses. Operating expenses associated with expanded compliance requirements may grow to approximately $9 million annually, with $6 million attributable to the Indiana operations. The Company expects to seek recovery under Senate Bill 251 referenced below, or such costs may be recoverable through current tracking mechanisms. Capital investments, driven by the pipeline safety regulations, associated with the Company's Indiana gas utilities are expected to be approximately $80 million over the next five years, which would likely qualify as federally mandated regulatory requirements. In Ohio, capital investments are expected to be approximately $55 million over the next five years. The Company expects to seek recovery of capital investments associated with complying with these federal mandates in accordance with Senate Bill 251 in Indiana and House Bill 95 in Ohio (referenced below).

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 or financial condition as the decrease in Deferred tax liabilities was generally offset by a $17.1 million decrease in Regulatory assets.

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 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 general rate case. Such costs include construction, depreciation, operating and other costs. The remaining 20 percent of those costs are to be deferred for recovery in the utility's next general rate case. 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.

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. Before the impacts of efficiency measures, the Company currently stands at approximately 5 percent of its electricity being provided by clean energy sources due to the long-term wind contracts and landfill gas investments. The Company continues to evaluate whether to participate in this voluntary program.

Ohio House Bill 95

In June 2011, Ohio House Bill 95 was 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. On February 3, 2012, the Company initiated a filing under House Bill 95. This filing requests accounting authority to defer depreciation, post in service carrying costs and property taxes for its approximate $25 million 2012 capital expenditure program. The capital expenditure program includes infrastructure expansion and improvements not covered by the Company's distribution replacement rider as well as expenditures necessary to comply with PUCO rules, regulations and orders. A procedural schedule associated with the filing has not yet been set.

10. Environmental Matters

Air Quality

Cross-State Air Pollution Rule (Formerly Clean Air Interstate Rule (CAIR))

On July 7, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR). CSPAR is the EPA's response to the US Court of Appeals for the District of Columbia's (the Court) remand of the Clean Air Interstate Rule (CAIR). CAIR was originally established in 2005 as an allowance cap and trade program that required reductions from coal-burning power plants for NOx emissions beginning January 1, 2009 and SO2 emissions beginning January 1, 2010, with a second phase of reductions in 2015.

In an effort to address the Court's finding that CAIR did not adequately ensure attainment of pollutants in certain downwind states due to unlimited trading of SO2and NOx allowances, CSPAR reduces the ability of facilities to meet emission reduction targets through allowance trading. Like CAIR, CSPAR sets individual state caps for SO2and NOx emissions. However, unlike CAIR in which states allocated allowances through state implementation plans, CSPAR allowances were allocated to individual units directly through the federal rule. As finalized, CSAPR requires a 71 percent reduction of SO_2 emissions compared to 2005 national levels and a 52 percent reduction of NO_x emissions compared to 2005 national levels and that such reductions are to be achieved with initial step reductions beginning January 1, 2012, with final compliance to be achieved in 2014. Multiple administrative and judicial challenges have been filed, including requests to stay CSPAR's implementation.

On December 30, 2011, the Court granted a stay of CSPAR and ordered expedited briefing schedules be submitted by January 18, 2012, that would allow for completion of briefing and a hearing in April 2012. Two primary issues are before the Court for review: (1) EPA's use of air modeling data (as opposed to exclusive reliance on actual monitoring data) to support state contribution levels, and (2) EPA's allocation of allowances directly through a federal implementation plan as opposed to setting state caps and providing states the opportunity to submit individual state implementation plans. In addition, there are initiatives in the Congress that, if adopted, would suspend CSPAR's implementation.

Utility Hazardous Air Pollutants (HAPs) Rule
On December 21, 2011, the EPA finalized the Utility HAPs rule. The HAPs Rule is the EPA's response to the US Court of Appeals for the District of Columbia vacating the Clean Air Mercury Rule (CAMR) in 2008. CAMR was originally established in 2005 as a nation-wide mercury emission allowance cap and trade system which sought to reduce utility emissions of mercury starting in 2010.

The HAPs rule sets emission limits for hazardous air pollutants for existing and new coal-fired power plants and identifies the following broad categories of hazardous air pollutants: mercury, non-mercury hazardous air pollutants (primarily arsenic, chromium, cobalt, and selenium) and acid gases (hydrogen cyanide, hydrogen chloride, and hydrogen fluoride). The rule imposes mercury emission limits for two sub-categories of coal, and proposed surrogate limits for non-mercury and acid gas hazardous air pollutants. The EPA did not grant blanket compliance extensions, but asserted that states have broad authority to grant one year extensions for individual units where potential reliability impacts have been demonstrated. Reductions are to be achieved within three years of publication of the final rule in the Federal register (early 2015). Initiatives to suspend CSPAR's implementation by the Congress also apply to the implementation of the HAPs Rule.

Conclusions Regarding Air Regulations
To comply with Indiana's implementation plan of the Clean Air Act, and other federal air quality standards, the Company obtained authority from the IURC to invest in clean coal technology. Using this authorization, the Company invested approximately $411 million starting in 2001 with the last equipment being placed into service on January 1, 2010. The pollution control equipment included Selective Catalytic Reduction (SCR) systems, fabric filters, and an SO2 scrubber at its generating facility that is jointly owned with 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 obtained April 27, 2011. SIGECO's coal fired generating fleet is 100 percent scrubbed for SO2 and 90 percent controlled for NOx.

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

The Company is currently reviewing the sufficiency of its existing pollution control equipment in relation to the requirements described in CSPAR and the Utility HAPs Rule. Based upon an initial review of the final rules, including minor revisions made to CSPAR in October 2011, 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 and additional operating expenses could be required. The Company believes that such additional costs, if necessary, would be recoverable under Indiana Senate Bill 251 referenced above.

Water
Section 316(b) of the Clean Water Act requires that generating facilities use the "best technology available" to minimize adverse environmental impacts in a body of water. More specifically, Section 316(b) is concerned with impingement and entrainment of aquatic species in once-through cooling water intake structures used at electric generating facilities. In April 2009, the U.S. Supreme Court affirmed that the EPA could, but was not required to, consider costs and benefits in making the evaluation as to the best technology available for existing generating facilities. The regulation was remanded back to the EPA for further consideration. In March 2011, the EPA released its proposed Section 316(b) regulations. The EPA did not mandate the retrofitting of cooling towers in the proposed regulation, but if finalized the regulation will leave it to the state to determine whether cooling towers should be required on a case by case basis. A final rule is expected in 2012. Depending on the final rule and on the Company's facts and

circumstances, capital investments could be in the $40 million range if new infrastructure, such as new cooling water towers, is required. Costs for compliance with these final regulations would likely qualify as federally mandated regulatory requirements under Indiana Senate Bill 251 referenced above.

Coal Ash Waste Disposal & Ash Ponds

In June 2010, the EPA issued proposed regulations affecting the management and disposal of coal combustion products, such as ash generated by the Company's coal-fired power plants. The proposed rules more stringently regulate these byproducts and would likely increase the cost of operating or expanding existing ash ponds and the development of new ash ponds. The alternatives include regulating coal combustion by-products that are not being beneficially reused as hazardous waste. The EPA did not offer a preferred alternative, but took public comment on multiple alternative regulations. Rules may not be finalized in 2012 given oversight hearings, congressional interest, and other factors.

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

Climate Change

In April 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 2009, the EPA published its proposed endangerment finding for public comment. The proposed endangerment finding concludes that carbon emissions from mobile sources pose an endangerment to public health and the environment. The endangerment finding was finalized in December 2009, and is the first step toward EPA regulating carbon emissions through the existing Clean Air Act in the absence of specific carbon legislation from Congress. The EPA has promulgated two greenhouse gas regulations that apply to the Company's generating facilities. In 2009, the EPA finalized a mandatory greenhouse gas emissions registry which requires the reporting of emissions. The EPA has also finalized a revision to the Prevention of Significant Deterioration (PSD) and Title V permitting rules which would require facilities that emit 75,000 tons or more of greenhouse gases a year to obtain a PSD permit for new construction or a significant modification of an existing facility. The Company anticipates additional EPA rulemaking related to new generation sources and significant modifications to existing sources, but the timetable remains uncertain.

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 and natural gas distribution businesses. At this time and in the absence of final legislation or rulemaking, compliance costs and other effects associated with reductions in 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.

Manufactured Gas Plants

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

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

The Company has accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, the Company has recorded cumulative costs that it reasonably expects to incur totaling approximately $41.6 million ($23.1 million at Indiana Gas and $18.5 million at SIGECO). The estimated accrued costs are limited to the Company's share of the remediation efforts and are therefore net of exposures of other potentially responsible parties (PRP).

With respect to insurance coverage, Indiana Gas has received approximately $20.8 million from all known insurance carriers under insurance policies in effect when these plants were in operation. SIGECO 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 another site subject to a lawsuit that has been settled. In November 2011, 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 settlement agreements with all known insurance carriers and has recorded approximately $15.1 million of expected insurance recoveries.

The costs the Company expects to incur are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments, and inflation factors, among others. While the Company's utilities have recorded all costs which they presently expect to incur in connection with activities at these sites, it is possible that future events may require 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 December 31, 2011 and 2010, respectively, approximately $6.5 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.

Jacobsville Superfund Site

On July 22, 2004, the EPA listed the Jacobsville Neighborhood Soil Contamination site in Evansville, Indiana, on the National Priorities List under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The EPA has identified four sources of historic lead contamination. These four sources shut down manufacturing operations years ago. When drawing up the boundaries for the listing, the EPA included a 250 acre block of properties surrounding the Jacobsville neighborhood, including the Company's operations center. Vectren's property has not been named as a source of the lead contamination. Vectren's own soil testing, completed during the construction of the operations center, did not indicate that the Vectren property contains lead contaminated soils above industrial cleanup levels. At this time, it is anticipated that the EPA may request additional soil testing at some future date.

11. 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. 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 would be initiated.

Coal Procurement Procedures
Vectren South submitted a request for proposal in April 2011 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 case, a sub docket proceeding was established to review the Company's prospective coal procurement procedures, and the Company submitted evidence related to its recent request for proposal (RFP) and those coal procurement procedures to the IURC in September 2011. In October 2011, the OUCC filed its testimony which, while suggesting enhancements to the process to be considered, does not challenge the results of the RFP and the resulting new contracts. All hearings were completed in December 2011, and an order is expected in early 2012.

Vectren South Electric Fuel Cost Reduction
On December 5, 2011 within the quarterly Fuel Adjustment Clause (FAC) filing, Vectren South submitted a joint proposal with the OUCC to reduce its fuel costs by accelerating the impact of lower cost coal contracts to be effective after 2012. In the spring of 2011, Vectren secured contracts for lower coal costs through a formal bidding process. This lower-priced coal is expected to start being delivered and used at Vectren's power plants by late 2012 to early 2013 and beyond. The agreement to accelerate savings into early 2012 means that the existing 2012 coal costs that are above the new, lower prices will be deferred to a regulatory asset and recovered over a six-year period without interest beginning in 2014. This deferral also includes a reduction to the coal inventory balance at December 31, 2011 of approximately $17.7 million to reflect existing inventory at the new, lower price. The IURC approved this proposal on January 25, 2012, with an impact to customer's rates effective February 1, 2012.

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, and include some for large industrial customers. Core Plus programs are those programs not required specifically by the IURC, but defined by each utility to meet the overall energy savings targets defined by the IURC.

On August 31, 2011 the IURC issued an order approving an initial three year DSM plan in the Vectren South service territory that complies with the IURC's energy saving targets. Consistent with the Company's proposal, the order approved, among other items, the following: 1) recovery of costs associated with implementing the DSM Plan; 2) the recovery of a performance incentive mechanism based on measured savings related to certain DSM programs; 3) lost margin recovery associated with the implementation of DSM programs for large customers; and 4) deferral of lost margin up to $1 million in 2011 associated with small customer DSM programs for subsequent recovery under a tracking mechanism to be proposed by the Company. This mechanism is an alternative to the electric decoupling proposal that was denied by the IURC in the order received April 27, 2011. On January 26, 2012, the Company filed with the IURC a proposal for a small customer lost margin recovery mechanism within the existing Demand Side Management Adjustment (DSMA). The proposal includes a request for recovery of the $1 million deferred in 2011, and a request for continued deferral of lost margins in 2012 until such point as these lost margins are included in DSMA rates. The procedural schedule has not been set in this filing, but the Company expects an order in 2012.

Vectren South Electric Dense Pack Filing
On September 14, 2011, Vectren South filed a petition with the IURC seeking recovery of and return on the capital investment in dense pack technology to improve the efficiency of its A.B. Brown Generating Station. This investment is expected to be approximately $32 million over the next two years, of which approximately $19 million has been

invested to date. This technology is expected to allow the A.B. Brown units to run at least 5 percent more efficient, thereby burning less fuel, and reducing fuel costs and emissions of pollutants. Indiana statute provides for timely recovery of investments, with a return, in instances where the investment increases the efficiency of existing generating plants that are fueled by coal. Several parties have intervened in the case and are requesting that the IURC deny recovery of these project costs outside of a base rate proceeding. A hearing was held by the IURC in February 2012 and proposed orders are to be submitted by the parties in March 2012. An order is expected later in 2012.

Vectren North Reporting Location Consolidation Proceeding

Vectren North implemented a reporting location consolidation plan in 2011 and closed certain locations throughout the North territory. On May 26, 2011, the International Brotherhood of Electrical Workers Local 1393, United Steel Workers Locals 12213 and 7441 and others filed a formal complaint with the IURC claiming that the consolidation and simultaneous closing by Vectren North of select reporting locations endangers public safety and impairs Vectren North's ability to provide adequate, safe and reliable service. These parties have asked the IURC to require Vectren North to reopen previously consolidated reporting locations and maintain and staff those locations. A hearing in this case was held in February 2012, and the Company expects the IURC to act some time in 2012.

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. On August 18, 2011, the IURC issued an order approving the settlement as filed, granting the extension of the current decoupling mechanism in place at both gas companies and recovery of new conservation program costs through December 2015.

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 commenced on April 1, 2011. The results of that auction were approved by the PUCO on January 19, 2011. Vectren Source, the Company's former 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. Each tranche of customers equates to approximately 28,000 customers. As per the terms of the plan approved by the PUCO, because no application for a full exit of the merchant function was neither sought nor approved by April 1, 2011, VEDO conducted a third retail auction on January 31, 2012 to address the 12-month term beginning April 1, 2012. The results of that auction were approved by the PUCO on February 1, 2012. Consistent with current practice, customers 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.

12. Fair Value Measurements

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

	At December 31,			
	2011		2010	
(In millions)	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$1,208.2	$1,345.7	$1,304.8	$1,392.9
Short-term borrowings	142.8	142.8	47.0	47.0
Cash & cash equivalents	6.0	6.0	2.4	2.4

For the balance sheet dates presented in these financial statements, the Company had no material assets or liabilities recorded at fair value outstanding, and no material assets or liabilities valued using 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.

13. Segment Reporting

The Company’s operations consist of 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 Company is comprised of three operating segments: Gas Utility Services, Electric Utility Services, and Other Shared Service operations. Net income is the measure of profitability used by management for all operations.

Information related to the Company's business segments is summarized below:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Revenues			
Gas Utility Services	$819.1	$954.1	$1,066.0
Electric Utility Services	635.9	608.0	528.6
Other Operations	43.9	44.5	42.8
Eliminations	(41.9)	(42.9)	(41.2)
Total revenues	$1,457.0	$1,563.7	$1,596.2
Profitability Measure - Net Income			
Gas Utility Services	$52.5	$53.7	$50.2
Electric Utility Services	65.0	60.9	48.3
Other Operations	5.4	9.3	8.9
Total net income	$122.9	$123.9	$107.4

	Year Ended December 31,		
(In millions)	2011	2010	2009
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Gas Utility Services	$84.3	$80.7	$76.9
Electric Utility Services	80.2	80.8	77.5
Other Operations	27.8	26.7	26.5
Total depreciation & amortization	$192.3	$188.2	$180.9
Interest Expense			
Gas Utility Services	$37.1	$38.8	$38.8
Electric Utility Services	36.4	36.4	34.8
Other Operations	6.8	6.2	5.6
Total interest expense	$80.3	$81.4	$79.2
Income Taxes			
Gas Utility Services	$34.5	$35.1	$31.3
Electric Utility Services	45.3	40.8	27.4
Other Operations	3.1	1.2	0.5
Total income taxes	$82.9	$77.1	$59.2
Capital Expenditures			
Gas Utility Services	$113.5	$88.7	$121.1
Electric Utility Services	102.2	120.1	154.1
Other Operations	17.8	22.5	16.7
Non-cash costs & changes in accruals	1.8	(2.2)	15.0
Total capital expenditures	$235.3	$229.1	$306.9

	At December 31,		
(In millions)	2011	2010	2009
Assets			

Utility Group						
Gas Utility Services	$	2,125.2	$	2,161.7	$	2,102.4
Electric Utility Services		1,656.5		1,666.5		1,592.4
Other Operations, net of eliminations		192.8		96.3		128.3
Total assets	$	3,974.5	$	3,924.5	$	3,823.1

14. Additional Balance Sheet & Operational Information

Inventories consist of the following:

	At December 31,	
(In millions)	2011	2010
Gas in storage – at LIFO cost	$31.8	$26.2
Materials & supplies	38.6	37.3
Coal & oil for electric generation - at average cost	60.6	70.1
Other	1.5	1.6
Total inventories	$132.5	$135.2

Based on the average cost of gas purchased during December, the cost of replacing gas in storage carried at LIFO cost exceeded that carrying value at December 31, 2011, and 2010, by approximately $12 million and $14 million, respectively.

Prepayments & other current assets in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2011	2010
Prepaid gas delivery service	$42.4	$40.7
Prepaid taxes	5.1	34.3
Deferred income taxes	14.3	-
Other prepayments & current assets	7.5	8.4
Total prepayments & other current assets	$69.3	$83.4

Other investments in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2011	2010
Cash surrender value of life insurance policies	$25.9	$26.1
Municipal bond	3.9	4.1
Restricted cash	0.8	-
Other investments	1.2	1.1
Total other investments	$31.8	$31.3

Accrued liabilities in the Consolidated Balance Sheets consist of the following:

	At December 31,	
(In millions)	2011	2010
Refunds to customers & customer deposits	$56.4	$54.8
Accrued taxes	29.9	39.7
Accrued interest	17.5	19.7
Deferred income taxes	-	0.4
Accrued salaries & other	17.2	21.3
Total accrued liabilities	$121.0	$135.9

Asset retirement obligations included in the Consolidated Balance Sheets roll forward as follows:

(In millions)	2011	2010
Asset retirement obligation, January 1	$32.0	$32.9
Accretion	2.0	1.9
Increases (decreases) in estimates, net of cash payments	-	(2.8)
Asset retirement obligation, December 31	34.0	32.0
Accrued liabilities	$0.2	$0.2
Deferred credits & other liabilities	$33.8	$31.8

Other – net in the Consolidated Statements of Income consists of the following:

	Year Ended December 31,		
(In millions)	2011	2010	2009
AFUDC - borrowed funds	$2.5	$1.4	$1.3
AFUDC - equity funds	0.2	0.3	0.7
Nonutility plant capitalized interest	0.3	0.2	0.2
Interest income	0.6	0.6	0.7
Cash surrender value of life insurance policies	0.1	1.8	3.9
Other income	0.6	1.1	1.0
Total other – net	$4.3	$5.4	$7.8

Supplemental Cash Flow Information:

	Year Ended December 31,		
(In millions)	2011	2010	2009
Cash paid (received) for:			
Interest	$82.5	$81.4	$77.6
Income taxes	(3.4)	25.4	(26.1)

As of December 31, 2011 and 2010, the Company has accruals related to utility and nonutility plant purchases totaling approximately $9.2 million and $11.1 million, respectively.

15. Subsidiary Guarantor & Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of Utility Holdings' $350 million in short-term credit facilities, of which $243 million is outstanding at December 31, 2011, and Utility Holdings' $722 million unsecured senior notes outstanding at December 31, 2011. The guarantees are full and unconditional and joint and several, and Utility Holdings has no subsidiaries other than the subsidiary guarantors. However, Utility Holdings does have operations other than those of the subsidiary guarantors. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors, which are 100 percent owned, separate from the parent company's operations is required. Following are consolidating financial statements including information on the combined operations of the subsidiary guarantors separate from the other operations of the parent company. Pursuant to a tax sharing agreement, consolidating tax effects, which are calculated on a separate return basis, are reflected at the parent level.

Consolidating Statement of Income for the year ended December 31, 2011 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$819.1	$ -	$ -	$ 819.1
Electric utility	635.9	-	-	635.9
Other	-	43.9	(41.9)	2.0
Total operating revenues	1,455.0	43.9	(41.9)	1,457.0
OPERATING EXPENSES				
Cost of gas sold	375.4	-	-	375.4
Cost of fuel & purchased power	240.4	-	-	240.4
Other operating	354.6	-	(41.5)	313.1
Depreciation & amortization	164.6	27.1	0.6	192.3
Taxes other than income taxes	52.3	1.5	0.2	54.0
Total operating expenses	1,187.3	28.6	(40.7)	1,175.2
OPERATING INCOME	267.7	15.3	(1.2)	281.8
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	-	117.5	(117.5)	-
Other – net	3.1	48.9	(47.7)	4.3
Total other income (expense)	3.1	166.4	(165.2)	4.3
Interest expense	73.5	55.7	(48.9)	80.3
INCOME BEFORE INCOME TAXES	197.3	126.0	(117.5)	205.8
Income taxes	79.8	3.1	-	82.9
NET INCOME	$117.5	$122.9	$ (117.5)	$ 122.9

Consolidating Statement of Income for the year ended December 31, 2010 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$954.1	$-	$ -	$ 954.1
Electric utility	608.0	-	-	608.0
Other	-	44.5	(42.9)	1.6
Total operating revenues	1,562.1	44.5	(42.9)	1,563.7
OPERATING EXPENSES				
Cost of gas sold	504.7	-	-	504.7
Cost of fuel & purchased power	235.0	-	-	235.0
Other operating	341.9	-	(42.7)	299.2
Depreciation & amortization	161.1	26.7	0.4	188.2
Taxes other than income taxes	58.0	1.5	0.1	59.6
Total operating expenses	1,300.7	28.2	(42.2)	1,286.7
OPERATING INCOME	261.4	16.3	(0.7)	277.0
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	-	114.6	(114.6)	-
Other – net	4.3			