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, 2006

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, Evansville, Indiana	**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

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**

Table of Contents

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 o.

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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non-accelerated filer ý

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, 2006, 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**	**January 31, 2007**
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.

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, 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	Steven M. Schein Vice President, Investor Relations sschein@vectren.com

-2-

Table of Contents

Table of Contents

[(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.

Definitions

AFUDC: allowance for funds used during construction

APB: Accounting Principles Board

EITF: Emerging Issues Task Force

MMBTU: millions of British thermal units

MW: megawatts

	MWh / GWh: megawatt hours / thousands of megawatt hours (gigawatt hours)
FASB: Financial Accounting Standards Board	NOx: nitrogen oxide
FERC: Federal Energy Regulatory Commission	OUCC: Indiana Office of the Utility Consumer Counselor
IDEM: Indiana Department of Environmental Management	PUCO: Public Utilities Commission of Ohio
IURC: Indiana Utility Regulatory Commission	SFAS: Statement of Financial Accounting Standards
MCF / BCF: thousands / billions of cubic feet	USEPA: United States Environmental Protection Agency
MDth / MMDth: thousands / millions of dekatherms	Throughput: combined gas sales and gas transportation volumes

Table of Contents

PART I

ITEM 1. BUSINESS

Description of the Business

Vectren Utility Holdings, Inc. (Utility Holdings or the Company), 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), Southern Indiana Gas and Electric Company (SIGECO), and the Ohio operations. Utility Holdings also has assets that provide information technology and other services to the utilities.

Indiana Gas provides energy delivery services to approximately 565,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 141,000 electric customers and approximately 112,000 natural gas customers located near Evansville, in southwestern Indiana. SIGECO also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana.

The Ohio operations provide energy delivery services to approximately 318,000 natural gas customers located near Dayton in west central Ohio. The Ohio operations are owned as a tenancy in common by Vectren Energy Delivery of Ohio, Inc. (VEDO), a wholly owned subsidiary, (53% ownership) and Indiana Gas (47% ownership). The Ohio operations generally do business as Vectren Energy Delivery of Ohio.

Vectren, an Indiana corporation, is an energy holding company headquartered in Evansville, Indiana, and organized on June 10, 1999. Both Vectren and Utility Holdings were exempt from registration pursuant to Section 3(a) (1) and 3(c) of the Public Utility Holding Company Act of 1935, which was repealed effective February 8, 2006 by the Energy Policy Act of 2005 (Energy Act). Both Vectren and Utility Holdings are holding companies as defined by the Energy Act.

Narrative Description of the Business

The Company segregates its businesses into three operating segments: Gas Utility Services, Electric Utility Services, and Other Operations. The Gas Utility Services segment includes the operations of Indiana Gas, the Ohio operations, 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 includes the Company's power generating and marketing operations. The Company collectively refers to its gas and electric operating segments as its regulated operations. In total, these regulated operations supply natural gas and/or electricity to over one million customers. Other Operations primarily provide information technology and other support services to those utility operations.

At December 31, 2006, the Company had \$3.4 billion in total assets, with \$2.0 billion (57%) attributed to the Gas Utility Services, \$1.3 billion (37%) attributed to the Electric Utility Services, and \$0.2 billion (6%) attributed to Other Operations. Net income for the year ended December 31, 2006, was \$91.4 million with \$83.1 million attributed to regulated operations and \$8.3 million attributed to other operations. Net income for the year ended 2005 was \$95.1 million.

For further information, refer to Note 12 regarding the activities and assets of the Company's operating segments 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.

Table of Contents

Gas Utility Services

At December 31, 2006, the Company supplied natural gas service to approximately 995,000 Indiana and Ohio customers, including 909,000 residential, 84,000 commercial, and 2,000 industrial and other contract customers. This represents customer base growth of 0.3% compared to 2005.

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, appliance manufacturing, polycarbonate resin (Lexan®) and plastic products, gypsum products, electrical equipment, metal specialties, glass, steel finishing, pharmaceutical and nutritional products, gasoline and oil products, and coal mining. The largest Indiana communities served are Evansville, Muncie, Anderson, Lafayette, West Lafayette, Bloomington, Terre Haute, Marion, New Albany, Columbus, Jeffersonville, New Castle, and Richmond, and suburban areas surrounding Indianapolis. The largest community served outside of Indiana is Dayton, Ohio.

Revenues

For the year ended December 31, 2006, gas utility revenues were approximately $1,232.5 million, of which residential customers accounted for 66%, commercial 28%, and industrial and other contract customers 6%.

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 volumes of gas provided to both sales and transportation customers (throughput) were 182.6 MMDth for the year ended December 31, 2006. Gas transported or sold to residential and commercial customers was 97.7 MMDth representing 53% of throughput. Gas transported or sold to industrial and other contract customers was 84.9 MMDth representing 47% of throughput. Rates for transporting gas generally provide for the same margins earned by selling gas under applicable sales tariffs.

The sale of gas is seasonal and strongly affected by variations in weather conditions. To mitigate seasonal demand, the Company has storage capacity at seven active underground gas storage fields and six liquefied petroleum air-gas manufacturing plants. The Company also contracts with its affiliate, ProLiance Energy, LLC (ProLiance), and with other third party gas service providers to ensure availability of gas. ProLiance is an unconsolidated, nonutility, energy marketing affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas). (See Note 4 in the Company's consolidated financial statements included in "Item 8 Financial Statements and Supplementary Data" regarding transactions with ProLiance). 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. In addition, the Company prepays ProLiance for natural gas delivery services during the seven months prior to the peak heating season. The volume of gas per day that can be delivered during peak demand periods for each utility is located in "Item 2 Properties."

Gas Purchases

In 2006, the Company purchased 95,561 MDth volumes of gas at an average cost of $8.64 per Dth, of which approximately 72% was purchased from ProLiance and 28% was purchased from other third party providers. 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. As a result of the June 2005 PUCO order, the Company has established an annual bidding process for VEDO's gas supply and portfolio administration services. Since November 1, 2005, the Company has used a third party provider for these services. Prior to October 31, 2005, ProLiance supplied natural gas to all of the Company's regulated gas utilities. The average cost of gas per Dth purchased for the previous five years was $8.64 in 2006; $9.05 in 2005; $6.92 in 2004; $6.36 in 2003; and $4.57 in 2002.

Electric Utility Services

At December 31, 2006, the Company supplied electric service to approximately 141,000 Indiana customers, including 122,000 residential, 18,800 commercial, and 200 industrial and other customers. This represents customer base growth of 1% compared to 2005. In addition, the Company has firm power commitments to four municipalities and has contingency reserve requirements consistent with Reliability First Corp. standards.

Table of Contents

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

Revenues

For the year ended December 31, 2006, retail and firm wholesale electricity sales totaled 6,004.5 GWh, resulting in revenues of approximately $392.5 million. Residential customers accounted for 25% of 2006 revenues; commercial 22%; industrial 43%; and municipal and other 10%. In addition, the Company sold 898.3 GWh through optimization activities in 2006, generating revenue, net of purchased power costs, of $29.7 million.

Generating Capacity

Installed generating capacity as of December 31, 2006, was rated at 1,301 MW. Coal-fired generating units provide 1,006 MW of capacity, and natural gas or oil-fired turbines used for peaking or emergency conditions provide 295 MW.

In addition to its generating capacity, in 2006, the Company had 34 MW available under firm contracts and 62 MW available under interruptible contracts. The Company also had a firm purchase supply contract for a maximum of 73 MW for the cooling season months during 2006. This contract ended at the end of September 2006. Also, under the terms of the consent decree between SIGECO, the Department of Justice and USEPA, the Company discontinued operations of Culley Unit 1 (50 MW) effective December 31, 2006. The Company executed a capacity contract for a maximum of 100 MW for the years 2007-2009.

The Company has interconnections with Louisville Gas and Electric Company, Cinergy Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc., Big Rivers Electric Corporation, and the City of Jasper, Indiana, providing the historic ability to simultaneously interchange approximately 500 MW. However, the ability of the Company to effectively utilize the electric transmission grid in order to achieve its desired import/export capability has been, and may continue to be, impacted as a result of the ongoing changes in the operation of the midwestern transmission grid. The Company, as a member of the Midwest Independent System Operator (MISO), has turned over operational control of the interchange facilities and its own transmission assets, like many other Midwestern electric utilities, to MISO. See "Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition" regarding the Company's participation in MISO.

Total load for each of the years 2002 through 2006 at the time of the system summer peak, and the related reserve margin, is presented below in MW.

Date of summer peak load	8/10/2006	7/25/2005	7/13/2004	8/27/2003	8/5/2002
Total load at peak [1]	1,325	1,315	1,222	1,272	1,258
Generating capability	1,351	1,351	1,351	1,351	1,351
Firm purchase supply	107	107	105	32	82
Interruptible contracts	62	76	51	95	95
Total power supply capacity	1,520	1,534	1,507	1,478	1,528
Reserve margin at peak	15%	17%	23%	16%	21%

[1] The total load at peak is increased 25 MW in 2006, 2005, 2003, and 2002 from the total load actually experienced. The additional 25 MW represents load that would have been incurred if 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 those years. On the date of peak in 2004, Summer Cycler program was not activated.

Table of Contents

The winter peak load for the 2005-2006 season of approximately 935 MW occurred on December 20, 2005. The prior year winter peak load was approximately 932 MW, occurring on January 18, 2005.

The Company maintains a 1.5% interest in the Ohio Valley Electric Corporation (OVEC). The OVEC is comprised of 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 are entitled to 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. Because of this decreased demand, the Company's 1.5% interest in the OVEC makes available approximately 34 MW of capacity, in addition to its generating capacity, for use in other operations. Such generating capacity is included in firm purchase supply in the chart above.

Fuel Costs and Purchased Power

Electric generation for 2006 was fueled by coal (98%) and natural gas (2%). Oil was used only for testing of gas/oil-fired peaking units.

There are substantial coal reserves in the southern Indiana area, and coal for coal-fired generating stations has been supplied from operators of nearby Indiana coal mines, including those owned by Vectren Fuels, Inc., a wholly owned subsidiary of the Company. Approximately 3.5 million tons of coal were purchased for generating electricity during 2006, of which approximately 91% was supplied by Vectren Fuels, Inc. from its mines and third party purchases. The average cost of coal consumed in generating electric energy for the years 2002 through 2006 follows:

	Year Ended December 31,				
Avg. Cost Per	2006	2005	2004	2003	2002
Ton	$ 37.51	$ 30.27	$ 27.06	$ 24.91	$ 23.50
MWh	18.44	14.94	13.06	11.93	11.00

The Company also purchases power as needed from the wholesale market to supplement its generation capabilities in periods of peak demand; however, the majority of power purchased through the wholesale market is used to optimize and hedge the Company's sales to other wholesale customers. Volumes purchased in 2006 totaled 434,234 MWh.

Competition

The utility industry has undergone dramatic structural change for several years, resulting in increasing competitive pressures faced by electric and gas utility companies. Currently, several states, including Ohio, have passed legislation allowing electricity customers to choose their electricity supplier in a competitive electricity market and several other states are considering 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, 2006, approximately 72,000 customers in Utility Holdings' Ohio service territory purchase natural gas from a supplier other than the utility. 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 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 regulated environment and other environmental matters.

Table of Contents

Personnel

As of December 31, 2006, the Company and its consolidated subsidiaries had 1,599 employees, of which 828 are subject to collective bargaining arrangements.

In November 2005, the Company reached a four-year agreement with Local 175 of the Utility Workers Union of America, ending October 2009. In September 2005, the Company reached a four-year agreement with Local 135 of the Teamsters, Chauffeurs, Warehousemen, and Helpers Union, ending September 2009.

In July 2004, the Company reached a three-year labor agreement with Local 702 of the International Brotherhood of Electrical Workers, ending June 2007. In January 2004, the Company reached a five-year labor agreement, ending December 2008, with Local 1393 of the International Brotherhood of Electrical Workers and United Steelworkers of America Locals 12213 and 7441.

No contracts subject to collective bargaining expired in 2006. The next negotiation will be with the International Brotherhood of Electrical Workers Local 702, whose contract expires in June of 2007.

ITEM 1A. RISK FACTORS

The following factors 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.

The Company is a holding company, and its assets consist primarily of investments in its subsidiaries.

Dividends on the Company’s common stock depend on the earnings, financial condition, capital requirements and cash flow of its subsidiaries, Indiana Gas, SIGECO and VEDO, and the distribution or other payment of earnings from those entities to the Company. Should the earnings, financial condition, or capital requirements of, or legal requirements applicable to, them restrict their ability to pay dividends or make other payments to Utility Holdings, the Company’s ability to pay dividends to its parent could be adversely affected. Utility Holdings' results of operations, future growth and earnings and dividend goals also will depend on the performance of its subsidiaries.

The Company operates in an increasingly competitive industry, which may affect its future earnings.

The utility industry has been undergoing dramatic 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. Indiana has not adopted any regulation requiring gas choice except for large-volume customers. 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 the Company’s gas and electric utility sales are space heating and cooling. Accordingly, its operating results may fluctuate with variability of weather.

The Company’s gas and electric utility sales are sensitive to variations in weather conditions. Utility Holdings' forecasts utility sales on the basis of normal weather, which represents a long-term historical average. Since the Company does not have a weather-normalization mechanism for its electric operations or its Ohio natural gas operations, significant variations from normal weather could have a material impact on its earnings. However, the impact of weather on the gas operations in its Indiana territories has been significantly mitigated through the implementation on October 15, 2005, of a normal temperature adjustment mechanism.

Table of Contents

The Company's 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, appliance manufacturing, polycarbonate resin (Lexan®) and plastic products, gypsum products, electrical equipment, metal specialties, glass, steel finishing, pharmaceutical and nutritional products, gasoline and oil products, and coal mining.

Risks related to the regulation of the Company's businesses, including environmental regulation, could affect the rates the Company charges its customers, its costs and its profitability.

Utility Holdings' businesses are subject to regulation by federal, state and local regulatory authorities. In particular, the Company is subject to regulation by the FERC, the IURC and the PUCO. These authorities regulate many aspects of its transmission and distribution operations, including construction and maintenance of facilities, operations, safety, and the rates that the Company can charge customers and the rate of return that its utilities are authorized to earn. The Company's ability to obtain rate increases to maintain its current authorized rate of return depends upon regulatory discretion, and there can be no assurance that Utility Holdings will be able to obtain rate increases or rate supplements or earn its current authorized rate of return.

In addition, Utility Holdings' operations 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 and in connection with spills, releases and emissions of various substances in the environment. Such emissions from electric generating facilities include particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NOx), and mercury, among others.

Environmental legislation also requires that facilities, sites and other properties associated with Utility Holdings' 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 could result in material costs and liabilities. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by Utility Holdings subject to environmental regulation, its investment in environmentally compliant equipment, and the costs associated with operating that equipment, have increased and are expected to increase in the future.

Further, there are proposals to address global climate change that would regulate carbon dioxide (CO_2) and other greenhouse gases. Any future legislative or regulatory actions taken to address global climate change could adversely affect Utility Holdings' business and results of operations by, for example, requiring changes in, and increased costs related to, the Company's fossil fuel generating plants.

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

The Company may be subject to material litigation and regulatory proceedings from time to time. There can be no assurance that the outcome of these matters will not have a material adverse effect on its business, results of operations or financial condition.

The Company's electric 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 purchased power 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.

Table of Contents

Utility Holdings may experience significantly increased gas costs.

Commodity prices for natural gas purchases have increased and become more volatile in recent years. Subject to regulatory approval, Utility Holdings' subsidiaries are allowed recovery of gas costs from their retail customers through commission-approved gas cost adjustment mechanisms. As a result, profit margins on gas sales are not expected to be impacted. Nevertheless, regulators may disallow, and have in the past disallowed, recovery of a portion of gas costs for various reasons, including but limited to, a finding by the regulator that natural gas was not prudently procured, as an example. In addition, it is possible that as a result of this near term change in natural gas commodity prices, the Company's subsidiaries may experience increased interest expense due to higher working capital requirements, increased uncollectible accounts expense and unaccounted for gas and some level of price sensitive reduction in volumes sold or delivered. However, the Company believes that the negative earnings impact on the reduction of price sensitive natural gas volumes sold is significantly mitigated by Indiana and Ohio orders received in the fourth quarter of 2006 that authorize lost margin recovery.

The impact of MISO participation is uncertain.

Since February 2002 and with the IURC's approval, the Company has been a member of the MISO. The MISO serves the electrical transmission needs of much of the Midwest and maintains operational control over Utility Holdings' electric transmission facilities as well as that of other Midwest utilities.

On April 1, 2005, the MISO energy market commenced operation (the Day 2 energy market). As a result of being a market participant, Utility Holdings now bids its owned generation into the Day Ahead and Real Time markets and procure power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

As a result of MISO's operational control over much of the Midwestern electric transmission grid, including Utility Holdings' electric transmission facilities, its continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted. Given the nature of MISO's policies regarding use of transmission facilities, as well as ongoing FERC initiatives and uncertainties around Day 2 energy market operations, it is difficult to predict near term operational impacts. However, it is believed that MISO's regional operation of the transmission system will ultimately lead to reliability improvements within the Midwestern transmission system.

The potential need to expend capital for improvements to the transmission system, both to Utility Holdings' facilities as well as to those facilities of adjacent utilities, over the next several years will become more predictable as MISO completes studies related to regional transmission planning and improvements. Such expenditures may be significant.

Wholesale power marketing activities may add volatility to earnings.

Utility Holdings' regulated electric utility engages in wholesale power marketing activities that primarily involve asset optimization strategies. These optimization strategies 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. Projected 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.

Catastrophic events could adversely affect the Company's facilities and operations.

Catastrophic events such as fires, earthquakes, explosions, floods, tornados, terrorist acts or other similar occurrences could adversely affect Utility Holdings' facilities and operations.

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; 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.

Table of Contents

A downgrade in the Company's credit rating could negatively affect its ability to access capital.

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, Indiana Gas and SIGECO senior unsecured debt	Baa1	A-
Utility Holdings commercial paper program	P-2	A-2

The current outlook of both Moody's and Standard and Poor's is stable and are categorized 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.

Utility Holdings may be required to obtain additional permanent financing (1) to fund its capital expenditures, investments and debt security redemptions and maturities and (2) to further strengthen its capital structure and the capital structures of its subsidiaries. If the rating agencies downgrade the Company's credit ratings, particularly below investment grade, or withdraw its ratings, 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.

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 58,130 acres of land with an estimated ready delivery from storage capability of 5.6 BCF of gas with maximum peak day delivery capabilities of 145,000 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 for 17.8 BCF of storage with a maximum peak day delivery capability of 299,717 MMBTU per day. Indiana Gas' gas delivery system includes 12,505 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 underground gas storage fields located in Indiana covering 6,070 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 for 0.5 BCF of storage with a maximum peak day delivery capability of 19,166 MMBTU per day. SIGECO's gas delivery system includes 3,166 miles of distribution and transmission mains, all of which are located in Indiana.

The Ohio operations own and operate three liquefied petroleum (propane) air-gas manufacturing plants, all of which are located in Ohio. The plants can store .5 million gallons of propane, and the plants can manufacture for delivery

52,187 MCF of manufactured gas per day. In addition to its propane delivery capabilities, the Ohio operations have contracted for 12.0 BCF of storage with a maximum peak day delivery capability of 246,080 MMBTU per day. The Ohio operations' gas delivery system includes 5,356 miles of distribution and transmission mains, all of which are located in Ohio.

Table of Contents

Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2006, was rated at 1,301 MW. SIGECO's coal-fired generating facilities are the Brown Station with two units of 500 MW of combined capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Culley Station with two units of 356 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. Pursuant to the settlement between the Company, the Department of Justice, and the USEPA, the Company ceased operation of Culley Unit 1, with generating capacity of 50 MW, effective December 31, 2006 and is excluded from the total capacity above.

SIGECO's transmission system consists of 894 circuit miles of 138,000 and 69,000 volt lines. The transmission system also includes 30 substations with an installed capacity of 5,057 megavolt amperes (Mva). The electric distribution system includes 4,199 pole miles of lower voltage overhead lines and 331 trench miles of conduit containing 1,833 miles of underground distribution cable. The distribution system also includes 99 distribution substations with an installed capacity of 2,010 Mva and 52,449 distribution transformers with an installed capacity of 2,448 Mva.

SIGECO owns utility property outside of Indiana approximating nine miles of 138,000 volt electric transmission line which is 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 arising in the normal course of business. In the opinion of management, there are no legal proceedings 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. SUBMISSION OF MATTERS TO VOTE OF SECURITY HOLDERS

No matters were submitted during the fourth quarter to a vote of security holders.

Table of Contents

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 2006, Utility Holdings paid dividends to its parent company of $18.7 million in each of the first, second and third quarters, and $19.4 million in the fourth quarter.

During 2005, Utility Holdings paid dividends to its parent company of $20.0 million in each of the first, second and third quarters, and $20.7 million in the fourth quarter.

On January 31, 2007, the board of directors declared a $19.1 million dividend, payable to Vectren on February 28, 2007.

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.

Debt Security

The Company's 7 ¼% Senior Notes, due October 15, 2031, which were called in October 2006, previously traded on the New York Stock Exchange under the symbol "AVU." The high and low sales prices for the Company's publicly traded debt security as reported on the New York Stock Exchange are shown in the following table for the periods indicated.

	Price Range			Price Range	
2006	High	Low	**2005**	High	Low
First Quarter	$ 25.59	$ 25.00	First Quarter	$ 26.74	$ 25.44
Second Quarter	26.00	24.72	Second Quarter	26.30	25.40
Third Quarter	25.40	24.81	Third Quarter	26.35	25.05
Fourth Quarter	-	-	Fourth Quarter	25.80	25.00

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)	2006	2005	2004	2003	2002
Operating Data:					
Operating revenues	$ 1,656.5	$ 1,781.8	$ 1,498.0	$ 1,448.8	$ 1,236.9
Operating income	209.0	216.6	196.3	197.2	207.7
Net income	91.4	95.1	83.1	85.6	97.1
Balance Sheet Data:					
Total assets	$ 3,440.8	$ 3,391.2	$ 3,147.7	$ 2,925.1	$ 2,780.4
Redeemable preferred stock	-	-	0.1	0.2	0.3
Long-term debt - net of current maturities					
& debt subject to tender	1,025.3	997.8	941.3	960.5	841.2
Common shareholder's equity	1,056.7	1,023.8	985.4	979.8	768.6

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

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

For the year ended December 31, 2006, earnings were $91.4 million as compared to $95.1 million in 2005 and $83.1 million in 2004. The decline in 2006 results compared to 2005 is primarily due to continued declines in customer usage. Results reflect the impact of a constructive regulatory environment. The Company received orders in the fourth quarter of 2006 that authorize lost margin recovery related to the Company's Ohio customers and a majority of Indiana natural gas customers, and an order in the fourth quarter of 2005 for a normal temperature adjustment mechanism with respect to the Company's Indiana natural gas customers. The Company also utilizes rider mechanisms to recover capital expenditures associated with compliance with Clean Air Act and Clean Air Mercury requirements, among other costs. In addition, the Company has implemented base rate increases since 2003 and currently has two cases before the IURC where orders are expected in 2007. The revenue increases, including the proposed increases in the two pending cases, are required to offset increased operating and financing costs, the effect on usage from higher commodity prices, and the impact of recent weather unfavorable compared to 30-year normal temperatures.

Gas utility base rate increases added revenues of approximately $4.2 million in 2006 compared to 2005, and $33.8 million in 2005 compared to 2004. Increased revenues associated with recovery of pollution control investments were $2.6 million in 2006 compared to 2005 and $14.3 million in 2005 compared to 2004. Increased revenues associated with lost margin recovery were $2.0 million in 2006 compared to 2005.

In addition to customer usage declines, the decrease in earnings in 2006 was also impacted by higher depreciation and interest costs, and wholesale power marketing margins $6.2 million, or $3.7 million after tax, lower than the prior year. The decline was mitigated somewhat by the implementation of regulatory initiatives noted above, the impact of a lower effective tax rate, and a gain realized on the sale of a storage asset.

In 2005 compared to 2004, the $12 million increase is largely due to increased base rates, recovery of pollution control investments, weather, and wholesale power marketing activities. The improved utility margins were partially offset by higher operating and depreciation expense. The 2005 results also reflect a $4.1 million, $2.4 million after tax, charge recorded pursuant to the disallowance of Ohio gas costs.

Table of Contents

In 2006, 2005, and 2004 weather across all utilities was unfavorable compared to 30-year normal temperatures. Management estimates the after tax effect of weather compared to normal was unfavorable $4 million in 2006, unfavorable $3 million in 2005, and unfavorable $7 million in 2004. The 2006 weather effect contains the full impact of a normal temperature adjustment (NTA) mechanism implemented in the Company's Indiana natural gas service territories in the fourth quarter of 2005.

Utility Holdings generates revenue primarily from the delivery of natural gas and electric service to its customers. The 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. Results are impacted by weather patterns in its service territory and general economic conditions both in its service territory as well as nationally.

The Company has in place a disclosure committee that consists of senior management as well as financial management. The committee is actively involved in the preparation and review of the Company's SEC filings.

Significant Fluctuations

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 the *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 costs can be volatile and are generally collected on a dollar-for-dollar basis from customers. These measures exclude *Other operating expenses, Depreciation and amortization,* and *Taxes other than income taxes*, which are included in the calculation of operating income.

Margin generated from the sale of natural gas and electricity to residential and commercial customers is seasonal and is impacted by weather patterns in the Company's service territories. The weather impact in the Company's Indiana gas utility service territories is mitigated by a normal temperature adjustment mechanism, which was implemented in the fourth quarter of 2005. Margin generated from sales to large customers (generally industrial, other contract, and firm wholesale customers) is primarily impacted by overall economic conditions. Margin is also impacted by the collection of state mandated taxes, which fluctuate with gas costs, as well as other tracked expenses and is also impacted by some level of price sensitivity in volumes sold or delivered. Electric generating asset optimization activities are primarily affected by market conditions, the level of excess generating capacity, and electric transmission availability. 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)	2006	2005	2004
Gas utility revenues	$ 1,232.5	$ 1,359.7	$ 1,126.2
Cost of gas sold	841.5	973.3	778.5
Total gas utility margin	$ 391.0	$ 386.4	$ 347.7
Margin attributed to:			
Residential & commercial customers	$ 330.2	$ 333.2	$ 297.7
Industrial customers	48.0	48.3	45.7
Other customers	12.8	4.9	4.3
Sold & transported volumes in MMDth attributed to:			
Residential & commercial customers	97.7	112.9	114.5
Industrial customers	84.9	87.2	85.8

Total sold & transported volumes	**182.6**	**200.1**	**200.3**

Gas utility margins were $391.0 million for the year ended December 31, 2006, an increase of $4.6 million compared to 2005. A full year of base rate increases implemented in the Company's Ohio service territory which increased margin $4.2 million, a $4.1 million disallowance of Ohio gas costs in 2005, the effects of the normal temperature adjustment mechanism (NTA) implemented in 2005 in the Company's Indiana service territories, and the lost margin recovery authorizations implemented in the fourth quarter of 2006, more than offset the effects of warm weather, lower usage, and decreased tracked expenses recovered dollar for dollar in margin.

Table of Contents

For the year ended December 31, 2006, compared to 2005, management estimates that weather 14 percent warmer than normal and 9 percent warmer than prior year would have decreased margins $13.1 million compared to the prior year, had the NTA not been in effect. Weather, net of the NTA, resulted in an approximate $2.0 million year over year increase in gas utility margin. Incremental revenue associated with the lost margin recovery totaled $2.0 million in 2006. Further, for the year ended December 31, 2006, margin associated with tracked expenses and revenue taxes decreased $3.4 million. The average cost per dekatherm of gas purchased for the year ended December 31, 2006, was $8.64 compared to $9.05 in 2005 and $6.92 in 2004.

For the year ended December 31, 2005, gas utility margins increased $38.7 million compared to 2004. The increase is primarily due to the favorable impact of gas base rate increases of $33.8 million and additional pass through expenses and revenue taxes recovered in margins of $5.8 million compared to 2004. Results for the year ended December 31, 2005, reflect the disallowance of Ohio gas costs ordered by the PUCO described above. For the year ended December 31, 2005, weather was 5% warmer than normal but 4% colder than the prior year. Management estimates that weather, including the effects of the normal temperature adjustment mechanism, increased margin an estimated $2.5 million compared to 2004.

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

Electric Utility margin by revenue type follows:

	Year Ended December 31,		
(In millions)	2006	2005	2004
Electric utility revenues	$ 422.2	$ 421.4	$ 371.3
Cost of fuel & purchased power	151.5	144.1	116.8
Total electric utility margin	**$ 270.7**	**$ 277.3**	**$ 254.5**
Margin attributed to:			
Residential & commercial customers	$ 162.9	$ 170.8	$ 157.3
Industrial customers	70.2	66.9	63.7
Municipal & other customers	24.0	19.8	18.6
Subtotal: Retail & firm wholesale	**$ 257.1**	**$ 257.5**	**$ 239.6**
Asset optimization	$ 13.6	$ 19.8	$ 14.9
Electric volumes sold in GWh attributed to:			
Residential & commercial customers	2,789.7	2,933.2	2,830.9
Industrial customers	2,570.4	2,575.9	2,511.2
Municipal & other customers	644.4	689.9	645.9
Total retail & firm wholesale volumes sold	**6,004.5**	**6,199.0**	**5,988.0**

Retail & Firm Wholesale Margin

Electric retail and firm wholesale utility margin was $257.1 million for the year ended December 31, 2006 and was generally flat compared to 2005. The recovery of pollution control related investments and associated operating expenses and related depreciation increased margins $2.6 million year over year. Higher demand charges and other items increased industrial customer margin approximately $3.2 million year over year. These increases were offset by decreased residential and commercial usage. The decreased usage was due primarily to mild weather during the peak cooling season. For 2006 compared to 2005, the estimated decrease in margin due to unfavorable weather was $4.6 million ($4.0 million for below normal cooling weather and $0.6 million for heating weather). During 2006, cooling degree days were 5% below normal. In 2005, cooling degree days were 9% above normal.

Table of Contents

Electric retail and firm wholesale utility margin increased $17.9 million in 2005 compared to 2004. The recovery of pollution control related investments and associated operating expenses and depreciation expense increased margins $14.3 million compared to 2004. Cooling weather was 9% warmer than normal and 21% warmer than 2004. In 2005 compared to 2004, the estimated increase in electric margin related to weather was $4.0 million ($3.8 million related to cooling weather and $0.2 million related to heating weather).

Margin from Asset Optimization Activities

Periodically, generation capacity is in excess of that needed to serve retail load and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. These optimization strategies primarily involve the sale of excess generation into the MISO day ahead 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.

Following is a reconciliation of asset optimization activity:

	Year Ended December 31,		
(In millions)	2006	2005	2004
Off-system sales	$ 14.2	$ 15.3	$ 8.7
Transmission system sales	3.5	4.5	4.6
Other	(4.1)	0.0	1.6
Total asset optimization	$ 13.6	$ 19.8	$ 14.9

For the year ended December 31, 2006, net asset optimization margins were $13.6 million, which represents a decrease of $6.2 million compared to 2005. The decrease is due to the effect lower wholesale prices have had on the Company’s optimization portfolio and lower volumes sold off system. For the year ended December 31, 2005, net asset optimization margins increased $4.9 million as compared to 2004. The increase in margin results primarily from the timing of available capacity and mark to market gains.

In 2005, the Company experienced increased availability of the generating units. The availability of excess capacity was reduced in 2006 and 2004 by scheduled outages of owned generation related to the installation of environmental compliance equipment. Off-system sales totaled 889.4 GWh in 2006, compared to 1,208.1 GWh in 2005 and 670.4 GWh in 2004.

Operating Expenses

Other Operating

For the year ended December 31, 2006, other operating expenses decreased $2.3 million compared to 2005. Expenses in 2006 are reduced from the inclusion of a gain on the sale of a storage asset of approximately $4.4 million. Excluding this gain, operating expenses would have increased $2.1 million compared to 2005. The increase is primarily the result of electric generation chemical costs $1.3 million higher than the prior year. Bad debt expense in the Company’s Indiana service territories increased $0.6 million year over year due in part to higher gas costs.

Other operating expenses increased $20.9 million for the year ended December 31, 2005, compared to 2004. Amortization of rate case expenses, expenses associated with the Ohio choice program and integrity management programs, and expenses recovered through margin increased $6.5 million. Bad debt expense in the Company’s Indiana service territories was $9.3 million in 2005, an increase of $1.8 million compared to 2004. Compensation and benefit costs increases, including performance and share-based compensation, was $6.8 million higher than the prior year, reflective of the return to higher earnings in 2005 as compared to 2004. Higher maintenance, chemical costs, and all other costs account for $5.8 million of the increase.

Depreciation & Amortization

Depreciation expense increased $10.0 million in 2006 compared to 2005 and $13.5 million in 2005 compared to 2004. In addition to depreciation on additions to plant in service, the increases were primarily due to incremental depreciation expense associated with environmental compliance equipment additions. Depreciation expense associated with environmental compliance equipment, which is recovered in *Electric utility margin*, totaled $14.4 million in 2006, $12.1 million in 2005, and $6.2 million in 2004. Results for 2004 include $1.8 million of lower depreciation due to adjustments of Ohio depreciation rates and amortization of Indiana regulatory assets.

Table of Contents

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $1.0 million for the year ended December 31, 2006, compared to 2005 and increased $7.0 million in 2005 compared to 2004. The fluctuations are primarily attributable to variations in the collection of utility receipts, excise, and usage taxes. These variations resulted primarily from volatility in revenues and gas volumes sold.

Other Income (Expense)

Total other income (expense)-net increased $1.7 million in 2006 compared to 2005, and decreased $1.4 million in 2005 compared to 2004. The fluctuations relate primarily to capitalized interest on utility plant additions.

Interest Expense

In 2006, interest expense increased $7.6 million compared to 2005 and increased $2.5 million in 2005 compared to 2004. The increases are primarily driven by rising interest rates and higher levels of short-term borrowings due in part to higher working capital requirements resulting from the increased gas commodity prices.

Interest costs in 2006 also include the full impact of permanent financing transactions completed in the fourth quarter of 2005 in which $150 million in debt-related proceeds were received and used to retire short-term borrowings and other long-term debt. Results for 2006 also include a partial impact from financing transactions completed in October 2006 in which approximately $93 million in debt related proceeds were raised and used to retire debt outstanding with a higher interest rate.

Income Taxes

Federal and state income taxes decreased $9.8 million in 2006 compared to 2005 and increased $4.4 million in 2005 compared to 2004. The changes are impacted by fluctuations in pre-tax income. Income taxes recorded in 2006 reflect a $3.1 million favorable impact for an Indiana tax law change that resulted in the recalculation of certain state deferred income tax liabilities. Income taxes in 2006 also include other adjustments, including adjustments to reflect income taxes reported on 2005 state and federal income tax returns. Income taxes recorded in 2005 reflect favorable adjustments to accruals resulting from the conclusion of state tax audits and other adjustments.

Environmental Matters

The Company is subject to federal, state, and local regulations with respect to environmental matters, principally air, solid waste, and water quality. Pursuant to environmental regulations, the Company is required to obtain operating permits for the electric generating plants that it owns or operates and construction permits for any new plants it might propose to build. Regulations concerning air quality establish standards with respect to both ambient air quality and emissions from electric generating facilities, including particulate matter, sulfur dioxide (SO_2), nitrogen oxide (NOx), and mercury. Regulations concerning water quality establish standards relating to intake and discharge of water from electric generating facilities, including water used for cooling purposes in electric generating facilities. Because of the scope and complexity of these regulations, the Company is unable to predict the ultimate effect of such regulations on its future operations, nor is it possible to predict what other regulations may be adopted in the future, including any regulations to address the climate change issue.

Clean Air Act

Clean Air Interstate Rule & Clean Air Mercury Rule

In March of 2005 USEPA finalized two new air emission reduction regulations. The Clean Air Interstate Rule (CAIR) is an allowance cap and trade program requiring further reductions in Nitrogen Oxides (NOx) and Sulfur

Dioxide (SO_2) emissions from coal-burning power plants. The Clean Air Mercury Rule (CAMR) is an allowance cap and trade program requiring further reductions in mercury emissions from coal-burning power plants. Both sets of regulations require emission reductions in two phases. The first phase deadline for both rules is 2010 (2009 for NOx under CAIR), and the second phase deadline for compliance with the emission reductions required under CAIR is 2015, while the second phase deadline for compliance with the emission reduction requirements of CAMR is 2018. The Company is evaluating compliance options and fully expects to be in compliance by the required deadlines.

Table of Contents

In February 2006, the IURC approved a multi-emission compliance plan filed by the Company's utility subsidiary, SIGECO. Once the plan is implemented, SIGECO's coal-fired plants will be 100% scrubbed for SO_2, 90% scrubbed for NOx, and mercury emissions will be reduced to meet the new mercury reduction standards. The order, as previously agreed to by the OUCC and Citizens Action Coalition, allows SIGECO to recover an approximate 8% return on up to $110 million in capital investments through a rider mechanism which is updated every six months for actual costs incurred. The Company will also recover through a rider its operating expenses, including depreciation, once the equipment is placed into service. The order also stipulates that SIGECO study renewable energy alternatives and include a carbon forecast in future filings with regard to new generation and further environmental compliance plans, among other initiatives. As of December 31, 2006, the Company has made capital investments of approximately $62.2 million related to this environmental requirement.

NOx SIP Call Matter

The Company complied with Indiana's State Implementation Plan (SIP) of the Clean Air Act (the Act). These steps included installation of Selective Catalytic Reduction (SCR) systems at Culley Generating Station Unit 3 (Culley), Warrick Generating Station Unit 4, and A. B. Brown Generating Station Units 1 and 2. SCR systems reduce flue gas NOx emissions to atmospheric nitrogen and water using ammonia in a chemical reaction. This technology is known to currently be the most effective method of reducing nitrogen oxide (NOx) emissions where high removal efficiencies are required.

The IURC issued orders that approved:

- the Company's project to achieve environmental compliance by investing in clean coal technology;
- the Company's investment of $258 million in capital costs;
- a mechanism whereby, prior to an electric base rate case, the Company recovers through a rider that is updated every six months, an 8% return on its weighted capital costs for the project; and
- ongoing recovery of operating costs, including depreciation and purchased emission allowances, related to the clean coal technology now that facilities are placed into service.

Related annual operating expenses, including depreciation expense, were $18.7 million in 2006, $15.4 million in 2005, and $9.7 million in 2004.

Culley Generating Station Litigation

During 2003, the U.S. District Court for the Southern District of Indiana entered a consent decree among SIGECO, the Department of Justice (DOJ), and the USEPA that resolved a lawsuit originally brought by the USEPA against SIGECO. The lawsuit alleged violations of the Clean Air Act by SIGECO at its Culley Generating Station for (1) making modifications to a generating station without obtaining required permits, (2) making major modifications to the generating station without installing the best available emission control technology, and (3) failing to notify the USEPA of the modifications.

Under the terms of the agreement, the DOJ and USEPA agreed to drop all challenges of past maintenance and repair activities at the Culley Generating Station. In reaching the agreement, SIGECO did not admit to any allegations in the government's complaint, and SIGECO continues to believe that it acted in accordance with applicable regulations and conducted only routine maintenance on the units. SIGECO entered into this agreement to further its continued commitment to improve air quality and avoid the cost and uncertainties of litigation.

Under the agreement, SIGECO committed to:

- either repower Culley Unit 1 (50 MW) with natural gas and equip it with SCR control technology for further reduction of nitrogen oxide, or cease operation of the unit by December 31, 2006;
- operate the existing SCR control technology recently installed on Culley Unit 3 (287 MW) year round at a lower emission rate than that currently required under the NOx SIP Call, resulting in further nitrogen oxide reductions;
-

enhance the efficiency of the existing scrubber at Culley Units 2 and 3 for additional removal of sulphur dioxide emissions;

- install a baghouse for further particulate matter reductions at Culley Unit 3 by June 30, 2007;
- conduct a Sulphuric Acid Reduction Demonstration Project as an environmental mitigation project designed to demonstrate an advance in pollution control technology for the reduction of sulfate emissions; and
- pay a $600,000 civil penalty.

Table of Contents

The Company does not believe that implementation of the settlement will have a material effect on its results of operations or financial condition. The $600,000 civil penalty was expensed and paid during 2003. The Company ceased operation of Culley Unit 1 effective December 31, 2006 and the baghouse, which is included in the $110 million IURC order discussed above, went into service January 1, 2007.

Manufactured Gas Plants

In the past, Indiana Gas, SIGECO, and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable environmental laws and regulations, those that operated these facilities may now be required to take remedial action if certain byproducts are found above the regulatory thresholds at these sites.

Indiana Gas identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas completed a remedial investigation/feasibility study (RI/FS) at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. Although Indiana Gas has not begun an RI/FS at additional sites, Indiana Gas has submitted several of the sites to the IDEM's Voluntary Remediation Program (VRP) and is currently conducting some level of remedial activities, including groundwater monitoring at certain sites, where deemed appropriate, and will continue remedial activities at the sites as appropriate and necessary.

In conjunction with data compiled by environmental consultants, Indiana Gas accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, Indiana Gas has recorded costs that it reasonably expects to incur totaling approximately $20.4 million.

The estimated accrued costs are limited to Indiana Gas’ proportionate share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which serve to limit Indiana Gas’ share of response costs at these 19 sites to between 20% and 50%. With respect to insurance coverage, Indiana Gas has received and recorded settlements from all known insurance carriers in an aggregate amount approximating $20.4 million.

In October 2002, SIGECO received a formal information request letter from the IDEM regarding five manufactured gas plants that it owned and/or operated and were not enrolled in the IDEM’s VRP. In response, SIGECO submitted to the IDEM the results of preliminary site investigations conducted in the mid-1990’s. These site investigations confirmed that based upon the conditions known at the time, the sites posed no imminent and/or substantial risk to human health or the environment.

On October 6, 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO added those four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. That renewal was approved by the IDEM on February 24, 2004. On July 13, 2004, 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. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, SIGECO has recorded costs that it reasonably expects to incur totaling approximately $7.7 million. With respect to insurance coverage, SIGECO has received and recorded settlements from insurance carriers in an aggregate amount approximating the costs it expects to incur.

Table of Contents

Environmental matters related to Indiana Gas' and SIGECO's manufactured gas plants have had no material impact on results of operations or financial condition since costs recorded to date approximate PRP and insurance settlement recoveries. 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.

Jacobsville Superfund Site

On July 22, 2004, the USEPA 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 USEPA 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 USEPA included a 250 acre block of properties surrounding the Jacobsville neighborhood, including Vectren's Wagner Operations Center. Vectren's property has not been named as a source of the lead contamination, nor does the USEPA's soil testing to date indicate that the Vectren property contains lead contaminated soils. Vectren's own soil testing, completed during the construction of the Operations Center, did not indicate that the Vectren property contains lead contaminated soils. At this time, Vectren anticipates only additional soil testing, if required by the USEPA.

Global Climate Change

Global climate change remains a policy issue that is regularly considered for government regulation. If legislation requiring reductions in greenhouses gases is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company's fossil fuel plants.

Rate and Regulatory Matters

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

All metered gas rates in Indiana contain a gas cost adjustment (GCA) clause, and all metered gas rates in Ohio contain a gas cost recovery (GCR) clause. GCA and GCR clauses allow the Company to charge for changes in the cost of purchased gas. Metered electric rates contain a fuel adjustment clause (FAC) 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 an agreed upon benchmark, is also recovered through regulatory proceedings.

GCA, GCR, and FAC procedures involve periodic filings and IURC and PUCO 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 the estimated cost of gas, cost of fuel, and net energy cost of purchased power and actual costs incurred. The Company records any under-or-over-recovery resulting from gas and fuel adjustment clauses each month in margin. A corresponding asset or liability is recorded until the under-or-over-recovery is billed or refunded to utility customers.

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. For the recent past, the earnings test has not affected the Company's ability to recover costs.

Ohio and Indiana Lost Margin Recovery/Conservation Filings

In 2005, the Company filed conservation programs and conservation adjustment trackers in Indiana and Ohio designed to help customers conserve energy and reduce their annual gas bills. The programs would allow the Company to recover costs of promoting the conservation of natural gas through conservation trackers that work in tandem with a lost margin recovery mechanism. This mechanism is designed to allow the Company to recover the distribution portion of its rates from residential and commercial customers based on the level of customer revenues established in each utility’s last general rate case.

Table of Contents

Indiana
In December 2006, the IURC approved a settlement agreement between the Company and the OUCC that provides for a 5-year energy efficiency program to be implemented. The order allows the Company's Indiana utilities to recover the costs of promoting the conservation of natural gas through conservation trackers that work in tandem with a lost margin recovery mechanism that would provide for recovery of 85% of the difference between revenues actually collected by the Company and the revenues approved in the Company's most recent rate case. The order was implemented in the North service territory in December 2006 and will be implemented in South's service territory after its next general rate case (see below.) While most expenses associated with these programs are recoverable, in the first program year, the Company is required to fund $1.5 million in program costs without recovery. Revenues recorded in 2006 as a result of this order related to lost margin recovery totaled $0.7 million and revenues to fund energy efficiency programs totaled $0.6 million.

Ohio
In September 2006, the PUCO approved a conservation proposal that would implement a decoupling approach, including a related conservation program, for the Company's Ohio operations. The PUCO decision was issued following a hearing process and the submission of a settlement by the Company, the Ohio Consumer Counselor (OCC) and the Ohio Partners for Affordable Energy (OPAE). That settlement was contested by the PUCO Staff. In the decision the PUCO addressed decoupling by approving a two year, $2 million total, low-income conservation program to be funded by the Company, as well as a sales reconciliation rider intended to be a recovery mechanism for the difference between the weather normalized revenues actually collected by the Company and the revenues approved by the PUCO in the Company's most recent rate case. The decision produced an outcome that was different from the settlement. Following the decision, the Company and the OPAE advised the PUCO that they would accept the outcome even though it differed from the terms of the settlement. The OCC sought rehearing of the decision, which was denied in December, and thereafter the OCC advised the PUCO that the OCC was withdrawing from the settlement. At that point the OCC also initiated the process for appealing the PUCO's September and December decisions to the Ohio Supreme Court. Thereafter, the Company, the OPAE and the PUCO Staff advised the PUCO that they accepted the terms provided in the September decision, as affirmed by the December rehearing decision. Since that time there have been a number of procedural filings by the parties and presently the Company is awaiting a further decision from the PUCO. The Company believes that the PUCO had the necessary legal basis for its decisions and thus should confirm the outcome provided in the September decision. The Company began recognizing the impact of this order on October 1, 2006, and has recorded revenues in 2006 related to the order in the amount of $1.3 million.

Vectren South (Southern Indiana Gas & Electric) Base Rate Filings
On September 1, 2006, Vectren South filed petitions with the IURC to adjust its electric and gas base rates in its South service territory. The electric petition requests an increase of $76.7 million in base rates to recover the nearly $120 million additional investment in electric utility infrastructure since its last base rate increase in 1995, which is not currently included in rates charged to customers. The increase in rates also is required to support system growth, maintenance, reliability and recovery of costs deferred under previous IURC orders. The gas petition seeks to increase its gas base (non-gas cost) rates by $10.4 million to cover the ongoing costs of operating and maintaining its natural gas distribution and storage system. Based upon the timelines prescribed by the IURC at the start of these proceedings, decisions in each case are expected to be issued in the late summer of 2007. The initial public hearings in both cases have been conducted. On January 30, 2007, the OUCC filed testimony in the gas rate case proposing an increase of $5.1 million.

Integrated Gasification Combined Cycle (IGCC) Certificate of Public Convenience and Necessity
On September 7, 2006, Vectren Energy Delivery of Indiana and Duke Energy Indiana, Inc. filed with the IURC a joint petition for a Certificate of Public Convenience and Necessity (CPCN) for the construction of new electric capacity. Specifically, Vectren requested the IURC approve its construction and ownership of up to 20% of an IGCC project.

Vectren's CPCN filing also seeks timely recovery of its 20% portion of the project's construction costs as well as operation and maintenance costs and additional incentives available for the construction of clean coal technology. Initial studies of plant design have already begun, and if the project moves forward as currently designed, plant construction is expected to begin in 2007 and continue through 2011.

Table of Contents

Weather Normalization

On October 5, 2005, the IURC approved the establishment of a normal temperature adjustment (NTA) mechanism for Vectren Energy Delivery of Indiana. The OUCC had previously entered into a settlement agreement with Vectren Energy Delivery of Indiana providing for the NTA. The NTA affects the Company’s Indiana regulated residential and commercial natural gas customers and should mitigate weather risk in those customer classes during the October to April heating season. These Indiana customer classes represent approximately 60-65% of the Company’s total natural gas heating load.

The NTA mechanism will mitigate volatility in distribution charges created by fluctuations in weather by lowering customer bills when weather is colder than normal and increasing customer bills when weather is warmer than normal. The NTA has been applied to meters read and bills rendered after October 15, 2005. Each subsequent monthly bill for the seven-month heating season will be adjusted using the NTA. Resulting from this order, revenues recorded in 2006 totaled $13.6 million while refunds of $1.6 million were made in 2005.

The order provides that the Company will make, on a monthly basis, a commitment of $125,000 to a universal service fund program or other low-income assistance program for the duration of the NTA or until a general rate case.

Rate structures in the Company’s Indiana electric territory and Ohio gas territory do not include weather normalization-type clauses.

Gas Utility Base Rate Settlements in 2004 and 2005

On June 30, 2004, the IURC approved a $5.7 million base rate increase for SIGECO’s gas distribution business, and on November 30, 2004, approved a $24 million base rate increase for Indiana Gas’ gas distribution business. On April 13, 2005, the PUCO approved a $15.7 million base rate increase for VEDO’s gas distribution business. The base rate change in SIGECO’s service territory was implemented on July 1, 2004; the base rate change in Indiana Gas’ service territory was implemented on December 1, 2004; and the base rate change in VEDO’s service territory was implemented on April 14, 2005.

The orders also permit SIGECO and Indiana Gas to recover the on-going costs to comply with the Pipeline Safety Improvement Act of 2002. The Pipeline Safety Improvement Tracker provides for the recovery of incremental non-capital dollars, capped at $750,000 the first year and $500,000 thereafter for SIGECO and $2.5 million per year for Indiana Gas. Any costs incurred in excess of these annual caps are to be deferred for future recovery. VEDO’s new base rates provide for the recovery of some level of on-going costs to comply with the Pipeline Safety Improvement Act of 2002.

MISO

Since February 2002 and with the IURC’s approval, the Company has been a member of the Midwest Independent System Operator, Inc. (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. Pursuant to an order from the IURC received in December 2001, certain MISO startup costs (referred to as Day 1 costs) have been deferred for future recovery in the next general rate case, which was filed in 2006.

On April 1, 2005, the MISO energy market commenced operation (the Day 2 energy market). As a result of being a market participant, the Company now bids its owned generation into the Day Ahead and Real Time markets and procures power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

On June 1, 2005, Vectren, together with three other Indiana electric utilities, received regulatory authority from the IURC that allows recovery of fuel related costs and deferral of other costs associated with the Day 2 energy market. The order allows fuel related costs to be passed through to customers in Vectren’s existing fuel cost recovery proceedings. The other non-fuel and MISO administrative related costs are to be deferred for recovery as part of the next electric general rate case proceeding, which was filed in 2006. During 2006, the IURC reaffirmed the definition of certain costs as fuel related; the Company is following those guidelines.

Table of Contents

As a result of MISO's operational control over much of the Midwestern electric transmission grid, including SIGECO's transmission facilities, SIGECO's continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted. Given the nature of MISO's policies regarding use of transmission facilities, as well as ongoing FERC initiatives and uncertainties around Day 2 energy market operations, it is difficult to predict near term operational impacts. However, as stated above, it is believed that MISO's regional operation of the transmission system will ultimately lead to reliability improvements.

The potential need to expend capital for improvements to the transmission system, both to SIGECO's facilities as well as to those facilities of adjacent utilities, over the next several years will become more predictable as MISO completes studies related to regional transmission planning and improvements. Such expenditures may be significant.

Gas Cost Recovery (GCR) Audit Proceedings

On June 14, 2005, the PUCO issued an order disallowing the recovery of approximately $9.6 million of gas costs relating to the two-year audit period ended November 2002. That audit period provided the PUCO staff its initial review of the portfolio administration arrangement between VEDO and ProLiance. The disallowance includes approximately $1.3 million relating to pipeline refunds and penalties and approximately $4.5 million of costs for winter delivery services purchased by VEDO to ensure reliability over the two-year period. The PUCO also held that ProLiance should have credited to VEDO an additional $3.8 million more than credits actually received for the right to use VEDO's gas transportation capacity periodically during the periods when it was not required for serving VEDO's customers. The PUCO also directed VEDO to either submit its receipt of portfolio administration services to a request for proposal process or to in-source those functions. During 2003, the Company recorded a reserve of $1.1 million for this matter. An additional pretax charge of $4.1 million was recorded in *Cost of gas sold* in 2005. The reserve reflects management's assessment of the impact of the PUCO decisions, an estimate of any current impact that decision may have on subsequent audit periods, and an estimate of a sharing in any final disallowance by Vectren's partner in ProLiance.

VEDO filed its request for rehearing on July 14, 2005, and on August 10, 2005, the PUCO granted rehearing to further consider the $3.8 million portfolio administration issue and all interest on the findings, but denied rehearing on all other aspects of the case. On October 7, 2005, the Company filed an appeal with the Ohio Supreme Court requesting that the $4.5 million disallowance related to the winter delivery service issue be reversed. On December 21, 2005, the PUCO granted in part VEDO's rehearing request, and reduced the $3.8 million disallowance related to portfolio administration to $1.98 million. The Company has appealed the $1.98 million disallowance to the Ohio Supreme Court as well. Briefings of all matters and oral arguments were completed in November 2006, and the parties are awaiting the Court's ruling.

With respect to the most recent GCR audit covering the period of November 1, 2002 through October 31, 2005, the PUCO staff recommended a disallowance of approximately $830,000 related solely to the retention of a reserve margin for the winter of 2002/2003. The Company had previously reserved for the possible disallowance given the June 2005 PUCO order but has contested the disallowance. The PUCO will issue a decision on that issue in 2007.

As a result of the June 2005 PUCO order, the Company has established an annual bidding process for VEDO's gas supply and portfolio administration services. Since November 1, 2005, the Company has used a third party provider for these services.

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. Note 2 to the consolidated financial statements describes 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 impairments tests. The Company makes other estimates in the course of accounting for unbilled revenue, the effects of regulation, and intercompany allocations 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 depreciation of utility and non-utility plant, the valuation of derivative contracts, and the allowance for doubtful accounts, among others. Actual results could differ from these estimates.

Table of Contents

Goodwill

Pursuant to SFAS No. 142, 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 12 to the consolidated financial statements to be the reporting unit. An impairment test performed in accordance with SFAS 142 requires that a reporting unit's fair value be estimated. The Company used a discounted cash flow model 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 was in excess of the carrying amount in 2006, 2005, and 2004 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.

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. While certain estimates are used in the calculation of unbilled revenue, the method from which these estimates are derived is not subject to near-term changes.

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 SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). 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 of SFAS 71, 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. In the unlikely event of a change in the current regulatory environment, such write-offs and impairment charges could be significant.

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 based on 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.

Table of Contents

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. An allocation of expense is determined by Vectren's actuaries, comprised of only service cost and interest on that service cost, by subsidiary based on headcount at each measurement date, which occurs on September 30. These costs are directly charged to individual subsidiaries. Other components of costs (such as interest cost and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. 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 relies on actuarial estimates to assess the future potential liability and funding requirements of pension and postretirement plans. Vectren annually measures its obligations on September 30, and used the following weighted average assumptions to develop 2006 periodic benefit cost: a discount rate of 5.50 percent, an expected return on plan assets of 8.25 percent, a rate of compensation increase of 3.25 percent, and an inflation assumption of 3.50 percent. During 2006, Vectren increased the discount rate by 35 basis points to value 2006 ending pension and postretirement obligations and 2007 benefit cost due to an increase in benchmark interest rates. Future changes in health care costs, work force demographics, interest rates, or plan changes could significantly affect the estimated cost of these future benefits. Management estimates that a 50 basis point decrease in the discount rate would have increased 2006 periodic benefit cost by approximately $1.3 million.

Impact of Recently Issued Accounting Guidance

SFAS No. 158

On December 31, 2006, and after calculating the balance sheet impact of Vectren's retirement plans using the accounting guidance prescribed by SFAS 87 and SFAS 106, the Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS 158). SFAS 158 required Vectren to recognize the funded status of its pension plans and postretirement plans. SFAS 158 defines the funded status of a defined benefit plan as its assets less its projected benefit obligation, which includes projected salary increases, and defines the funded status of a postretirement plan as its assets less its accumulated postretirement benefit obligation. The impacts of adopting this standard were recorded at Vectren and are not reflected at the Utility Holdings level.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement does not require any new fair value measurements; however, the standard will impact how other fair value based GAAP is applied. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years with early adoption encouraged. The Company is currently assessing the impact this statement will have on its financial statements and results of operations.

FIN 48

In June 2006, the FASB issued FASB Interpretation No. 48 (FIN 48) "Accounting for Uncertainty in Income Taxes" an interpretation of SFAS 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of tax positions taken or expected to be taken in an income tax return. FIN 48 also provides guidance related to reversal of tax positions, balance sheet classification, interest and penalties, interim period accounting, disclosure and transition. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of this standard is not expected to have a material impact on operating results or financial condition.

Table of Contents

Financial Condition

Utility Holdings, the parent company, funds the short-term and long-term financing needs of its consolidated operations. Vectren does not guarantee Utility Holdings' debt. Utility Holdings' currently 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. Utility Holdings' long-term and short-term obligations outstanding at December 31, 2006, totaled $700.0 million and $270.1 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. Utility Holdings' operations have historically funded the significant portion of Vectren's common stock dividends.

The credit ratings on outstanding senior unsecured debt of Utility Holdings and Indiana Gas, at December 31, 2006, are A-/Baa1 as rated by Standard and Poor's Ratings Services (Standard and Poor's) and Moody's Investors Service (Moody's), respectively. SIGECO's credit ratings on outstanding secured debt are A/A3. Utility Holdings' commercial paper has a credit rating of A-2/P-2. The current outlook of both Moody's and Standard and Poor's is stable. A security rating is not a recommendation to buy, sell, or hold securities. The rating is subject to revision or withdrawal at any time, and each rating should be evaluated independently of any other rating. Standard and Poor's and Moody's lowest level investment grade rating is BBB- and Baa3, respectively.

The Company's consolidated equity capitalization objective is 45-55% of long-term capitalization. This objective may have varied, and will vary, depending on particular business opportunities, capital spending requirements, execution of long-term financing plans, and seasonal factors that affect the Company's operations. The Company's equity component was 50% and 49% of long-term capitalization at December 31, 2006, and 2005, respectively. Long-term capitalization includes long-term debt, including current maturities and debt subject to tender, as well as common shareholders' equity.

The Company expects a significant portion of its capital expenditures, investments, and debt security redemptions to be provided by internally generated funds. However, due to increased levels of forecasted capital expenditures the Company will likely require additional permanent financing. As of December 31, 2006, the Company was in compliance with all financial covenants.

Sources & Uses of Liquidity

Operating Cash Flow

The Company's primary historical source of liquidity to fund working capital requirements has been cash generated from operations, which totaled $286.1 million in 2006 compared to $265.8 million in 2005 and $232.9 million in 2004. The $20.3 million increase in cash flow in 2006 compared to 2005 is primarily attributable to favorable changes in working capital accounts, which offset increases in regulatory assets and plant removal costs and a $39.5 million decrease to cash related to deferred taxes.

Cash flow from operating activities increased $32.9 million in 2005 compared to 2004. Increased cash flow from operating activities is due to increased earnings before noncash charges and less cash utilized to support working capital increases. Earnings before noncash charges were $289.2 million in 2005 compared to $269.2 million in 2004, and cash utilized for working capital increases was $13.0 million in 2005 compared to $24.4 million in 2004.

Financing Cash Flow

Although working capital requirements are generally funded by cash flow from operations, the Company uses short-term borrowings to supplement working capital needs when accounts receivable balances are at their highest and gas storage is refilled. Additionally, short-term borrowings are required for capital projects and investments until they are financed on a long-term basis.

Table of Contents

Cash flow required for financing activities reflects the impact of long-term financing arrangements executed in 2006 and 2005. In 2006, Utility Holdings issued $100 million of senior unsecured securities and used those proceeds to retire higher coupon long-term debt. In 2005, Utility Holdings issued $150 million of senior unsecured securities and used those proceeds to retire higher coupon long-term debt and refinance certain capital projects originally financed with short-term borrowings. In 2006 and 2005, Utility Holdings received an additional capital contribution from Vectren totaling $20.0 million in both years. Utility Holdings used proceeds from these capital contributions to retire higher coupon long-term debt and refinance certain capital projects originally financed with short-term borrowings. These transactions are more fully described below.

Utility Holdings 2006 Debt Issuance
In October 2006, Utility Holdings issued $100 million in 5.95% senior unsecured notes due October 1, 2036 (2036 Notes). The 30-year notes were priced at par. The 2036 Notes are guaranteed by Utility Holdings' three public utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. These notes, as well as the timely payment of principal and interest, are insured by a financial guaranty insurance policy issued by Financial Guaranty Insurance Company (FGIC).

The 2036 Notes have no sinking fund requirements, and interest payments are due quarterly. The notes may be called by Utility Holdings, in whole or in part, at any time on or after October 1, 2011, at 100% of principal amount plus accrued interest. During the first and second quarters of 2006, Utility Holdings entered into several interest rate hedges with a $100 million notional amount. Upon issuance of the notes, these instruments were settled, resulting in the payment of approximately $3.3 million, which was recorded as a *Regulatory asset* pursuant to existing regulatory orders. The value paid is being amortized as an increase to interest expense over the life of the issue maturing October 2036.

The net proceeds from the sale of the 2036 Notes and settlement of the hedging arrangements totaled approximately $92.8 million. These proceeds were used to repay most of the $100 million outstanding balance of Utility Holdings' 7.25% Senior Notes originally due October 15, 2031. These notes were redeemed on October 19, 2006 at par plus accrued interest.

Utility Holdings 2005 Debt Issuance
In November 2005, Utility Holdings issued senior unsecured notes with an aggregate principal amount of $150 million in two $75 million tranches. The first tranche was 10-year notes due December 2015, with an interest rate of 5.45% priced at 99.799% to yield 5.47% to maturity (2015 Notes). The second tranche was 30-year notes due December 2035 with an interest rate of 6.10% priced at 99.779% to yield 6.11% to maturity (2035 Notes).

The notes are guaranteed by Utility Holdings' three public utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. The notes have no sinking fund requirements, and interest payments are due semi-annually. The notes may be called by Utility Holdings, in whole or in part, at any time for an amount equal to accrued and unpaid interest, plus the greater of 100% of the principal amount or the sum of the present values of the remaining scheduled payments of principal and interest, discounted to the redemption date on a semi-annual basis at the Treasury Rate, as defined in the indenture, plus 20 basis points for the 2015 Notes and 25 basis points for the 2035 Notes.

In January and June 2005, Utility Holdings entered into forward starting interest rate swaps with a notional value of $75 million. Upon issuance of the debt, the interest rate swaps were settled resulting in the receipt of approximately $1.9 million in cash, which was recorded as a *regulatory liability* pursuant to existing regulatory orders. The value received is being amortized as a reduction of interest expense over the life of the issue maturing December 2035.

The net proceeds from the sale of the senior notes and settlement of related hedging arrangements approximated $150 million and were used to repay short-term borrowings and to retire approximately $50 million of long-term debt with higher interest rates.

Table of Contents

Additional Capital Contributions

During the years ended December 31, 2006, 2005, and 2004, the Company has cumulatively received additional capital of $43.1 million from Vectren. Of that total, $40.0 million was funded by Vectren's nonregulated operations, and $3.1 million was funded by new share issues from Vectren's dividend reinvestment plan.

Long-Term Debt Put & Call Provisions

Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. The put or call provisions are not triggered by specific events, but are based upon dates stated in the note agreements, such as when notes are re-marketed. During 2006 and 2005, no debt was put to the Company. During 2004, debt totaling $2.5 million was put to the Company. Debt that may be put to the Company within one year is classified as *Long-term debt subject to tender* in current liabilities.

Utility Holdings, SIGECO and Indiana Gas Debt Calls

In 2006, the Company called at par $100.0 million of Utility Holdings senior unsecured notes originally due in 2031. In 2005, the Company called at par $49.9 million of Indiana Gas insured quarterly senior unsecured notes originally due in 2030, and in 2004, called at par $20.0 million of Indiana Gas insured quarterly senior unsecured notes originally due in 2015. The notes called in 2006, 2005 and 2004 had stated interest rates of 7.25%, 7.45% and 7.15%, respectively.

Other Financing Transactions

At December 31, 2005, $53.7 million of SIGECO notes could be put to the Company in March of 2006, the date of their next remarketing. In March of 2006, the notes were successfully remarketed, and are now classified in *Long-term debt.* Prior to the remarketing, the notes had tax-exempt interest rates ranging from 4.75% to 5.00%. After the remarketing, interest rates are reset every seven days using an auction process.

During 2004, the Company remarketed two first mortgage bonds outstanding at SIGECO. The remarketing effort converted $32.8 million of outstanding fixed rate debt into variable rate debt where interest rates reset every seven days using an auction process. One bond, due in 2023, had a principal amount of $22.8 million and an interest rate of 6%. The other bond, due in 2015, had a principal amount of $10.0 million and an interest rate of 4.3%. These remarketing efforts resulted in the extinguishment and reissuance of debt at generally the same par value.

Other Company debt totaling $15.0 million in 2004 was retired as scheduled.

Investing Cash Flow

Cash flow required for investing activities was $249.9 million in 2006, $217.7 million in 2005, and $242.7 million in 2004. Capital expenditures are the primary component of investing activities. Capital expenditures were $250.0 in 2006 compared to $217.8 million in 2005 and $246.2 million in 2004. Expenditures in 2006 and 2004 include higher levels of expenditures for environmental compliance equipment.

Available Sources of Liquidity

At December 31, 2006, the Company has $520 million of short-term borrowing capacity, of which approximately $250 million is available.

During the fourth quarter of 2005, in response to higher natural gas prices, Utility Holdings increased its available consolidated short-term borrowing capacity to $520 million, a $165 million increase over previous levels. In addition, Utility Holdings extended the maturity of its largest credit facility, which totals $515 million, through November 2010.

Vectren periodically issues new shares to satisfy dividend reinvestment plan and stock option plan requirements and contributes those proceeds to Utility Holdings. During 2004, these new issuances added additional liquidity of $3.1 million.

Table of Contents

Potential & Future Uses of Liquidity

Contractual Obligations

The following is a summary of contractual obligations at December 31, 2006:

(In millions)	Total	2007	2008	2009	2010	2011	Thereafter
Long-term debt [1]	$ 1,055.7	$ 6.5	$ -	$ -	$ -	$ 250.0	$ 799.2
Short-term debt	270.1	270.1	-	-	-	-	-
Long-term debt interest commitments	919.6	62.7	62.5	62.5	62.5	61.1	608.3
Plant purchase commitments [2]	390.5	64.5	113.0	115.0	70.0	28.0	-
Total	$ 2,635.9	$ 403.8	$ 175.5	$ 177.5	$ 132.5	$ 339.1	$ 1,407.5

(1) Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. These provisions allow holders to put debt back to the Company at face value or the Company to call debt at face value or at a premium. Long-term debt subject to tender during the years following 2006 (in millions) is $20.0 in 2007, zero in 2008, $80.0 in 2009, $10.0 million in 2010, $30.0 in 2011 and zero thereafter.

(2) The settlement period of these obligations is estimated.

The Company's regulated utilities have both firm and non-firm commitments to purchase commodities 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 and their insignificant impact to earnings, they have not been included in the listing of contractual obligations.

Planned Capital Expenditures

The timing and amount of capital expenditures, including contractual purchase commitments discussed above, for the five-year period 2007 - 2011 are estimated as follows (in millions): $297.4 in 2007, $323.6 in 2008, $351.8 in 2009, $281.7 in 2010, and $222.7 in 2011.

Pension and Postretirement Funding Obligations

Vectren believes making contributions to its qualified pension plans in the coming years will be necessary. Management currently estimates that the qualified pension plans will require Utility Holdings to contribute approximately $3 million in 2007 and approximately $7 million in 2008. During 2006, Vectren made contributions of $8.3 million, all of which were funded by Utility Holdings.

Table of Contents

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" and similar 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 supply 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.*
- *Increased competition in the energy environment including 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 an economic downturn, inflation rates, commodity prices, and monetary fluctuations.*
- *Increased natural gas 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, or work stoppages.*
- *Legal and regulatory delays and other obstacles associated with mergers, acquisitions and investments in joint ventures.*
- *Costs and other effects of legal and administrative proceedings, settlements, investigations, claims, and other matters, including, but not limited to, those described in Management's Discussion and Analysis of Results of Operations and Financial Condition.*
- *Changes in federal, state or local legislative requirements, such as changes in tax laws or rates, environmental laws and regulations.*

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

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the use of derivatives. The Company also executes 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 purchases and sales of natural gas and electricity for retail customers due to current Indiana and Ohio 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. Nevertheless, it is possible regulators may disallow recovery of a portion of gas costs for various reasons, including but not limited to, a finding by the regulator that natural gas was not prudently procured, as an example. Although Vectren's regulated operations are exposed to limited commodity price risk, volatile natural gas prices can result in higher working capital requirements, increased expenses including unrecoverable interest costs, uncollectible accounts expense, and unaccounted for gas, and some level of price- sensitive reduction in volumes sold or delivered. The Company mitigates these risks by executing derivative contracts that manage the price of forecasted natural gas purchases. These contracts are subject to regulation which allows for reasonable and prudent hedging costs to be recovered through rates. Constructive regulatory orders, such as the Indiana and Ohio orders authorizing lost margin recovery, also mitigate these risks. When regulation is involved, SFAS 71 controls when the offset to mark-to-market accounting is recognized in earnings.

Commodity prices for natural gas purchases have remained above historical levels and continue to be more volatile. Despite hedging strategies, this near term change in natural gas commodity prices may have significant effects on operating results as described above.

Wholesale Power Marketing

The Company's wholesale power marketing activities include asset optimization strategies that manage the utilization of available electric generating capacity. These optimization strategies involve the sale of excess generation into the MISO day ahead and real-time markets. As part of these strategies, the Company may also execute energy contracts that commit the Company to purchase and sell electricity in the future. 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 and offsetting forward purchase contracts. The Company accounts for asset optimization contracts that are derivatives at fair value with the offset marked to market through earnings.

Market risk resulting from commodity contracts is measured by management using the potential impact on pre-tax earnings caused by the effect a 10% adverse change in forward commodity prices might have on market sensitive derivative positions outstanding on specific dates. For the year ended December 31, 2005, a 10% adverse change in forward commodity prices would have decreased earnings by $0.3 million based upon open positions existing on the last day of that year. No such derivative contracts were outstanding on December 31, 2006.

Sales to Municipalities and Other Industrial Customers

The Company purchases and sells electricity to meet the demands of certain municipalities and large industrial customers. Price risk from forward positions obligating the Company to deliver commodities is mitigated with generating capability and offsetting forward purchase contracts. These contracts are expected to be settled by physical receipt or delivery of the commodity.

Table of Contents

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 manages this risk by allowing 20% and 30% of its total debt to be exposed to variable rate volatility. However, there are times when this targeted range of interest rate exposure may not be attained. To manage this exposure, the Company may use derivative financial instruments. At December 31, 2006, debt subject to short-term interest rate volatility and seasonal increases in short-term debt outstanding, represented 27% of the Company's total debt portfolio.

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 2006 and 2005, the weighted average combined borrowings under these arrangements were $263.6 million and $225.9 million, respectively. At December 31, 2006, and 2005, combined borrowings under these arrangements were $351.7 million and $259.3 million, respectively. Based upon average borrowing rates under these facilities during the years ended December 31, 2006 and 2005, an increase of 100 basis points (one percentage point) in the rates would have increased interest expense by $2.6 million and $2.3 million, respectively.

Other Risks

By using forward purchase contracts and derivative financial instruments to manage risk, the Company exposes itself 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 a diversified base of 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.

Table of Contents

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 controls 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, 2006. Management certified this fact in its Sarbanes Oxley Section 302 certifications, which are attached as exhibits to this 2006 Form 10-K.

Table of Contents

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") as of December 31, 2006 and 2005, and the related consolidated statements of income, shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 16, 2007

Table of Contents

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

	At December 31, 2006	2005
ASSETS		
Current Assets		
Cash & cash equivalents	$ 28.5	$ 11.7
Accounts receivable - less reserves of $2.5 &		
$2.6, respectively	134.8	170.7
Receivables due from other Vectren companies	0.3	2.2
Accrued unbilled revenues	121.4	212.5
Inventories	141.9	126.2
Recoverable fuel & natural gas costs	1.8	15.4
Prepayments & other current assets	103.2	117.2
Total current assets	**531.9**	**655.9**
Utility Plant		
Original cost	3,820.2	3,632.0
Less: accumulated depreciation & amortization	1,434.7	1,380.1
Net utility plant	**2,385.5**	**2,251.9**
Investments in unconsolidated affiliates	0.2	0.2
Other investments	21.4	21.0
Nonutility property - net	163.1	160.0
Goodwill - net	205.0	205.0
Regulatory assets	116.8	89.9
Other assets	16.9	7.3
TOTAL ASSETS	**$ 3,440.8**	**$ 3,391.2**

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, 2006	2005
LIABILITIES & SHAREHOLDER'S EQUITY		
Current Liabilities		
Accounts payable	$ 136.2	$ 131.9
Accounts payable to affiliated companies	68.2	140.6
Payables to other Vectren companies	25.3	29.2
Refundable fuel & natural gas costs	35.3	7.6
Accrued liabilities	115.8	130.4
Short-term borrowings	270.1	226.9
Current maturities of long-term debt	6.5	-
Long-term debt subject to tender	20.0	53.7
Total current liabilities	**677.4**	**720.3**
Long-Term Debt - Net of Current Maturities & Debt Subject to Tender	1,025.3	997.8
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	282.2	275.5
Regulatory liabilities	291.1	272.9
Deferred credits & other liabilities	108.1	100.9
Total deferred credits & other liabilities	**681.4**	**649.3**
Commitments & Contingencies (Notes 7 - 10)		
Common Shareholder's Equity		
Common stock (no par value)	632.9	612.9
Retained earnings	422.9	406.9
Accumulated other comprehensive income	0.9	4.0
Total common shareholder's equity	**1,056.7**	**1,023.8**
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	**$ 3,440.8**	**$ 3,391.2**

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

Table of Contents

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

	Year Ended December 31,		
	2006	2005	2004
OPERATING REVENUES			
Gas utility	$ 1,232.5	$ 1,359.7	$ 1,126.2
Electric utility	422.2	421.4	371.3
Other	1.8	0.7	0.5
Total operating revenues	**1,656.5**	**1,781.8**	**1,498.0**
OPERATING EXPENSES			
Cost of gas sold	841.5	973.3	778.5
Cost of fuel & purchased power	151.5	144.1	116.8
Other operating	239.0	241.3	220.4
Depreciation & amortization	151.3	141.3	127.8
Taxes other than income taxes	64.2	65.2	58.2
Total operating expenses	1,447.5	1,565.2	1,301.7
OPERATING INCOME	**209.0**	**216.6**	**196.3**
OTHER INCOME			
Other - net	7.6	5.9	7.1
Equity in earnings of unconsolidated affiliates	-	-	0.2
Total other income	7.6	5.9	7.3
Interest expense	77.5	69.9	67.4
INCOME BEFORE INCOME TAXES	**139.1**	**152.6**	**136.2**
Income taxes	47.7	57.5	53.1
NET INCOME	**$ 91.4**	**$ 95.1**	**$ 83.1**

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

Table of Contents

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

	Year Ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 91.4	$ 95.1	$ 83.1
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	151.3	141.3	127.8
Deferred income taxes & investment tax credits	(6.4)	33.1	43.0
Expense portion of pension & postretirement periodic benefit cost	4.2	4.0	4.1
Provision for uncollectible accounts	13.6	14.4	10.7
Other non-cash (income) expense - net	(2.4)	1.3	0.5
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	115.3	(88.1)	(78.0)
Inventories	(15.7)	(68.2)	(3.5)
Recoverable fuel & natural gas costs	41.3	3.6	8.9
Prepayments & other current assets	16.7	23.3	(2.9)
Accounts payable, including to Vectren companies & affiliated companies	(74.7)	100.7	37.9
Accrued liabilities	(14.2)	15.7	13.2
Changes in noncurrent assets	(27.2)	(8.4)	(1.9)
Changes in noncurrent liabilities	(7.1)	(2.0)	(10.0)
Net cash flows from operating activities	**286.1**	**265.8**	**232.9**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt - net of issuance costs & hedging proceeds	92.8	150.0	32.4
Additional capital contribution	20.0	20.0	3.1
Requirements for:			
Dividends to parent	(75.4)	(80.7)	(80.6)
Retirement of long-term debt, including premiums paid	(100.0)	(49.9)	(70.5)
Redemption of preferred stock of subsidiary	-	(0.1)	(0.1)
Net change in short-term borrowings, including from other Vectren companies	43.2	(81.4)	123.1
Net cash flows from financing activities	**(19.4)**	**(42.1)**	**7.4**
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from other investing activities	0.1	0.1	3.5
Requirements for capital expenditures, excluding AFUDC equity	(250.0)	(217.8)	(246.2)
Net cash flows from investing activities	**(249.9)**	**(217.7)**	**(242.7)**

Net (decrease) increase in cash & cash equivalents		16.8		6.0		(2.4)
Cash & cash equivalents at beginning of period		11.7		5.7		8.1
Cash & cash equivalents at end of period	$	28.5	$	11.7	$	5.7
Cash paid during the year for:						
Interest	$	75.2	$	65.9	$	65.0
Income taxes		49.8		43.3		6.1

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

Table of Contents

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

	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at January 1, 2004	$ 589.8	$ 390.0	$ -	$ 979.8
Net income and comprehensive income		83.1		83.1
Common stock:				
Additional capital contribution	3.1			3.1
Dividends		(80.6)		(80.6)
Balance at December 31, 2004	**$ 592.9**	**$ 392.5**	**$ -**	**$ 985.4**
Comprehensive income:				
Net income		95.1		95.1
Cash flow hedge				
Unrealized gains - net of $2.9 million in tax			4.2	4.2
Reclassification to net income - net of $0.2 million in tax			(0.2)	(0.2)
Total comprehensive income				99.1
Common stock:				
Additional capital contribution	20.0			20.0
Dividends		(80.7)		(80.7)
Balance at December 31, 2005	**$ 612.9**	**$ 406.9**	**$ 4.0**	**$ 1,023.8**
Comprehensive income:				
Net income		91.4		91.4
Cash flow hedge				
Unrealized losses - net of $1.5 million in tax			(2.1)	(2.1)
Reclassification to net income - net of $0.7 million in tax			(1.0)	(1.0)
Total comprehensive income				88.3
Common stock:				
Additional capital contribution	20.0			20.0
Dividends		(75.4)		(75.4)
Balance at December 31, 2006	**$ 632.9**	**$ 422.9**	**$ 0.9**	**$ 1,056.7**

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

Table of Contents

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

1. Organization and Nature of Operations

Vectren Utility Holdings, Inc. (Utility Holdings or the Company), an Indiana corporation, serves as the intermediate holding company for Vectren Corporation's (Vectren) three operating public utilities, Indiana Gas Company, Inc. (Indiana Gas), Southern Indiana Gas and Electric Company (SIGECO), and the Ohio operations. Utility Holdings also has assets that provide information technology and other services to the utilities. Vectren is an energy holding company headquartered in Evansville, Indiana. Both Vectren and Utility Holdings were exempt from registration pursuant to Section 3(a) (1) and 3(c) of the Public Utility Holding Company Act of 1935, which was repealed effective February 8, 2006 by the Energy Policy Act of 2005 (Energy Act). Both Vectren and Utility Holdings are holding companies as defined by the Energy Act.

Indiana Gas provides energy delivery services to approximately 565,000 natural gas customers located in central and southern Indiana. SIGECO provides energy delivery services to approximately 141,000 electric customers and approximately 112,000 gas customers located near Evansville in southwestern Indiana. SIGECO also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market. Indiana Gas and SIGECO generally do business as Vectren Energy Delivery of Indiana. The Ohio operations provide energy delivery services to approximately 318,000 natural gas customers located near Dayton in west central Ohio. The Ohio operations are owned as a tenancy in common by Vectren Energy Delivery of Ohio, Inc. (VEDO), a wholly owned subsidiary, (53% ownership) and Indiana Gas (47% ownership). The Ohio operations generally do business as Vectren Energy Delivery of Ohio.

2. Summary of Significant Accounting Policies

A. Principles of Consolidation

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

B. 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.

C. Inventories

Inventories consist of the following:

	At December 31,	
(In millions)	2006	2005
Gas in storage – at average cost	$ 61.3	$ 63.3
Materials & supplies	28.0	29.9
Gas in storage – at LIFO cost	26.5	18.8
Fuel (coal & oil) for electric generation	26.0	14.1
Other	0.1	0.1
Total inventories	**$ 141.9**	**$ 126.2**

Based on the average cost of gas purchased during December, the cost of replacing gas in storage carried at LIFO cost exceeded LIFO cost at December 31, 2006, and 2005, by approximately $79.0 million and $117.0 million, respectively. Gas in storage of the Indiana regulated operations is stated at LIFO. All other inventories are carried at average cost.

Table of Contents

D. Utility Plant & Depreciation

Utility plant is stated at historical cost, including AFUDC. Depreciation rates, which include a cost of removal component, are established through regulatory proceedings and are applied to all in-service utility 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)	2006		2005	
	Original Cost	Depreciation Rates as a Percent of Original Cost	Original Cost	Depreciation Rates as a Percent of Original Cost
Gas utility plant	$ 1,956.1	3.6%	$ 1,879.1	3.5%
Electric utility plant	1,685.5	3.7%	1,611.4	3.7%
Common utility plant	45.2	2.6%	44.2	2.6%
Construction work in progress	133.4	-	97.3	-
Total original cost	**$ 3,820.2**		**$ 3,632.0**	

AFUDC represents the cost of borrowed and equity funds used for construction purposes, and is charged to construction work in progress during the construction period. AFUDC is included in *Other - net* in the Consolidated Statements of Income. The total AFUDC capitalized into utility plant and the portion of which was computed on borrowed and equity funds for all periods reported follows:

	Year Ended December 31,					
(In millions)	2006		2005		2004	
AFUDC – borrowed funds	$	2.6	$	1.6	$	1.6
AFUDC – equity funds		1.5		0.3		1.6
Total AFUDC capitalized	**$**	**4.1**	**$**	**1.9**	**$**	**3.2**

Maintenance and repairs, including the cost of removal of minor items of property and planned major maintenance projects, are charged to expense as incurred. 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*. Costs to dismantle and remove retired property are charged against *Regulatory liabilities*, where the cost of removal obligation is classified in these financial statements.

Jointly Owned Plant

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, 2006 is $63.2 million with accumulated depreciation totaling $43.5 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.

E. Nonutility Property

Nonutility property, net of accumulated depreciation and amortization follows:

	At December 31,			
(In millions)	2006		2005	
Computer hardware & software	$	105.4	$	103.3
Land & buildings		44.9		43.5
All other		12.8		13.2
Nonutility property - net	**$**	**163.1**	**$**	**160.0**

The depreciation of nonutility property is charged against income over its estimated useful life (ranging from 5 to 40 years), using the straight-line method of depreciation. Repairs and maintenance, which are not considered improvements and do not extend the useful life of the nonutility property, are charged to expense as incurred. 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. Nonutility property is presented net of accumulated depreciation and amortization totaling \$113.7 million and \$92.7 million as of December 31, 2006, and 2005, respectively. For the years ended December 31, 2006, 2005 and 2004, the Company capitalized interest totaling \$0.7 million, \$0.6 million, and \$1.4 million, respectively, on nonutility plant construction projects.

Table of Contents

F. Impairment Review of Long-Lived Assets

Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This review is performed in accordance with SFAS No. 144 “Accounting for the Impairment or Disposal of Long-Lived Assets” (SFAS 144). SFAS 144 establishes one accounting model for all impaired long-lived assets and long-lived assets to be disposed of by sale or otherwise. SFAS 144 requires that the evaluation for impairment involve the comparison of an asset’s carrying value to the estimated future cash flows that the asset is expected to generate over its remaining life. If this evaluation were to conclude that the carrying value of the asset is impaired, an impairment charge would be recorded based on the difference between the asset’s 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.

G. Goodwill

Goodwill arising from business combinations is accounted for in accordance with SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). SFAS 142 requires a portion of goodwill be charged to expense only when it is impaired. The Company tests its goodwill for impairment at a reporting unit level at least annually and that test is performed at the beginning of each year. Impairment reviews consist of a comparison of the fair value of a reporting unit to its carrying amount. If the fair value of a reporting unit is less than its carrying amount, an impairment loss is recognized in operations. Through December 31, 2006, no goodwill impairments have been recorded. All of the Company’s goodwill is included in the Gas Utility Services operating segment.

H. Asset Retirement Obligations

SFAS No. 143 requires entities to record 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 entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss. To the extent regulation is involved, such gain or loss may be deferred.

Asset retirement obligations total $18.3 million at December 31, 2006 and $17.3 million at December 31, 2005, and are included in *Other Liabilities*. During 2006, the Company recorded accretion of $1.0 million. In 2005, the Company recorded accretion of $0.1 million and recorded additional liabilities of $16.0 million, related to the adoption of FASB Interpretation No. 47.

I. 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 rate-making and accounting practices of these agencies and to accounting principles generally accepted in the United States, including the provisions of SFAS No. 71 “Accounting for the Effects of Certain Types of Regulation” (SFAS 71).

Refundable or Recoverable Gas Costs and 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 an agreed upon benchmark, 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 for electric generation is charged to operating expense when consumed.

Regulatory Assets and 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 assesses the recoverability of costs recognized as regulatory assets and liabilities and the ability to continue to account for its activities based on the criteria set forth in SFAS 71. Based on current regulation, the Company believes such accounting is appropriate. If all or part of the Company's operations cease to meet the criteria of SFAS 71, 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.

Table of Contents

Regulatory assets consist of the following:

	At December 31,	
(In millions)	2006	2005
Future amounts recoverable from ratepayers:		
Income taxes	$ 13.3	$ 11.1
Asset retirement obligations & other	5.2	1.7
	18.5	12.8
Amounts deferred for future recovery:		
Demand side management programs	27.7	26.7
MISO-related costs	17.1	9.4
Cost recovery riders & other	4.7	2.5
	49.5	38.6
Amounts currently recovered through base rates:		
Unamortized debt issue costs	23.1	20.2
Premiums paid to reacquire debt	6.0	6.5
Demand side management programs & other	3.3	4.5
	32.4	31.2
Amounts currently recovered through tracking mechanisms:		
Ohio authorized trackers	10.3	5.6
Indiana authorized trackers	6.1	1.7
	16.4	7.3
Total regulatory assets	**$ 116.8**	**$ 89.9**

Of the $32.4 million currently being recovered through base rates charged to customers, $1.5 million is earning a return. The weighted average recovery period of regulatory assets currently being recovered is 14.4 years. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable.

Regulatory liabilities consist of the following:

	At December 31,	
(In millions)	2006	2005
Advances from rate-payers related to:		
Cost of removal	$ 270.6	$ 251.4
Asset retirement obligations	11.3	11.6
	281.9	263.0
Amounts currently amortizing related to:		
Interest rate hedging proceeds	6.1	6.8
Amounts deferred for future settlement related to:		
MISO-related costs	3.1	3.1
Total regulatory liabilities	**$ 291.1**	**$ 272.9**

Cost of Removal

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 as defined by SFAS No. 143, “Accounting for Asset Retirement Obligations” and its related interpretations (SFAS 143).

Table of Contents

Asset Retirement Obligations

A portion of removal costs related to interim retirements of gas utility pipeline and utility poles, certain asbestos-related issues, and reclamation activities meet the definition of an asset retirement obligation (ARO). The regulatory liability above represents a timing difference between cost recognition described in SFAS 143, and cost recognition established in regulatory proceedings for these obligations.

J. Comprehensive Income

Comprehensive income is a measure of all changes in equity that result from the non-shareholder transactions. This information is reported in the Consolidated Statements of Common Shareholders' Equity. A summary of the components of and changes in *Accumulated other comprehensive income* for the past three years follows:

	2004			2005		2006	
(In millions)	Beginning of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance	Changes During Year	End of Year Balance
Cash flow hedges	-	-	-	6.7	6.7	(5.3)	1.4
Deferred income taxes	-	-	-	(2.7)	(2.7)	2.2	(0.5)
Accumulated other comprehensive income (loss)	**$ -**	**$ -**	**$ -**	**$ 4.0**	**$ 4.0**	**$ (3.1)**	**$ 0.9**

K. 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.

L. Excise and Utility Receipts Taxes

Excise taxes and a portion of utility receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues, which totaled $39.7 million in 2006, $42.6 million in 2005, and $38.3 million in 2004. Excise and utility receipts taxes paid are recorded as a component of *Taxes other than income taxes*.

M. Earnings Per Share

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

N. Other Significant Policies

Included elsewhere in these notes are significant accounting policies related to intercompany allocations and income taxes (Note 3) and derivatives (Note 10).

O. Use of Estimates

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

3. Transactions with Other Vectren Companies

Support Services and 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 based on cost. Utility Holdings received corporate allocations totaling $43.7 million, $48.0 million, and $44.5 million for the years ended December 31, 2006, 2005, and 2004, respectively.

Vectren Fuels, Inc., a wholly owned subsidiary of Vectren, owns and operates coal mines from which SIGECO purchases fuel used for electric generation. Amounts paid for such purchases for the years ended December 31, 2006, 2005, and 2004, totaled $116.8 million, $96.4 million, and $79.0 million, respectively.

Table of Contents

Miller Pipeline Corporation

Effective July 1, 2006, Vectren purchased the remaining 50% ownership in Miller Pipeline Corporation (Miller), making Miller a wholly owned subsidiary of Vectren. Prior to the transaction, Miller was 50% owned by Vectren and was accounted for by Vectren using the equity method of accounting. Miller 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 paid by Utility Holdings and its subsidiaries totaled 17.1 million in 2006, $13.6 million in 2005 and $22.6 million in 2004. Amounts owed to Miller at December 31, 2006 are included in *Payables to other Vectren companies* and at December 31, 2005 are included in *Accounts payable to affiliated companies*.

Retirement Plans and Other Postretirement Benefits

Vectren has multiple defined benefit pension plans and postretirement plans that require accounting as described in SFAS No. 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS 158), which it adopted on December 31, 2006. An allocation of expense is determined by Vectren's actuaries, comprised of only service cost and interest on that service cost, by subsidiary based on headcount at each measurement date. These costs are directly charged to individual subsidiaries. Other components of costs (such as interest cost and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. Neither plan assets nor the ending liability is allocated to individual subsidiaries since these assets and obligations are derived from corporate level decisions. Further, Vectren satisfies the future funding requirements of plans and the payment of benefits from general corporate assets. This allocation methodology is consistent with "multiemployer" benefit accounting as described in SFAS 87 and 106.

For the years ended December 31, 2006, 2005, and 2004, periodic pension costs totaling $5.3 million, $4.8 million, and $4.8 million, respectively, were directly charged by Vectren to the Company. For the years ended December 31, 2006, 2005, and 2004, other periodic postretirement benefit costs totaling $0.6 million, $0.8 million, and $0.9 million, respectively, were directly charged by Vectren to the Company. As of December 31, 2006 and 2005, $44.2 million and $49.5 million, respectively, is included in *Deferred credits & other liabilities* and represents expense directly charged to the Company that is yet to be funded to Vectren, and $5.9 million and $3.0 million, respectively, is included in *Other assets* for amounts funded in advance to Vectren.

Cash Management Arrangements

The Company participates in a centralized cash management program with Vectren, other wholly owned subsidiaries, and banks.

Share-Based Incentive Plans

In December 2004, the FASB issued Statement 123 (revised 2004), "Share-Based Payments" (SFAS 123R) that required compensation costs related to all share-based payment transactions to be recognized in the financial statements. With limited exceptions, the amount of compensation cost is measured based on the grant-date fair value of the equity or liability instruments issued. Compensation cost is recognized over the period that an employee provides service in exchange for the award. SFAS 123R replaced SFAS 123 and superseded APB 25. The Company adopted SFAS 123R using the modified prospective method on January 1, 2006. The adoption of this standard, and subsequent interpretations of the standard, did not have a material effect on the Company's operating results or financial condition. Utility Holdings does not have share-based compensation plans separate from Vectren. An insignificant number of Utility Holdings' employees participate in Vectren's share-based compensation plans.

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.

-46-

Table of Contents

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

	Year Ended December 31,		
(In millions)	2006	2005	2004
Current:			
Federal	$ 43.3	$ 15.7	$ 3.7
State	10.8	8.7	6.4
Total current taxes	**54.1**	**24.4**	**10.1**
Deferred:			
Federal	(0.9)	32.2	40.6
State	(3.5)	3.3	4.6
Total deferred taxes	**(4.4)**	**35.5**	**45.2**
Amortization of investment tax credits	(2.0)	(2.4)	(2.2)
Total income tax expense	**$ 47.7**	**$ 57.5**	**$ 53.1**

The liability method of accounting is used for income taxes under which deferred income taxes are recognized to reflect the tax effect of temporary differences between the book and tax bases of assets and liabilities at currently enacted income tax rates. Significant components of the net deferred tax liability follow:

	At December 31,	
(In millions)	2006	2005
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	$ 271.8	$ 277.5
Regulatory assets recoverable through future rates	21.0	19.2
Demand side management programs	8.4	7.7
Other comprehensive income	0.5	2.7
Employee benefit obligations	(24.4)	(20.7)
Regulatory liabilities to be settled through future rates	(7.7)	(8.1)
Other – net	12.6	(2.8)
Net noncurrent deferred tax liability	282.2	275.5
Current deferred tax liabilities:		
Deferred fuel costs - net	(1.9)	7.6
Other net	(1.6)	-
Net deferred tax liability	**$ 278.7**	**$ 283.1**

At December 31, 2006 and 2005, investment tax credits totaling $9.9 million and $11.8 million, respectively, are included in *Deferred credits and other liabilities*. These investment tax credits are amortized over the lives of the related investments.

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

	Year Ended December 31,		
	2006	2005	2004
Statutory rate	35.0%	35.0%	35.0%
State and local taxes-net of federal benefit	5.5	5.2	5.2
Tax law change	(2.2)	-	-
Amortization of investment tax credit	(1.4)	(1.5)	(1.6)
Adjustment to income tax accruals	(2.8)	(2.2)	(0.2)
All other - net	0.2	1.2	0.6
Effective tax rate	34.3%	37.7%	39.0%

-47-

Table of Contents

4. Transactions with Vectren Affiliates

ProLiance Energy, LLC
ProLiance Energy, LLC (ProLiance), a nonutility gas marketing and energy management affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas), provides natural gas and related services to the Company's utilities, Citizens Gas, and others. ProLiance's primary businesses include gas marketing, gas portfolio optimization, and other portfolio and energy management services.

Transactions with ProLiance
Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2006, 2005, and 2004, totaled $610.2 million, $908.9 million, and $789.8 million, respectively. Amounts owed to ProLiance at December 31, 2006 and 2005, for those purchases were $68.2 million and $137.4 million, respectively, and are included in *Accounts payable to affiliated companies* in the Consolidated Balance Sheets. The Company purchased approximately 72% of its gas through ProLiance in 2006, compared to 95% in 2005 and 100% in 2004. Amounts charged by ProLiance for gas supply services are established by supply agreements with each utility.

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. ProLiance has not provided gas supply/portfolio administration services to VEDO since October 31, 2005.

Other Affiliate Transactions
Vectren has ownership interests in other affiliated companies accounted for using the equity method of accounting that performed facilities locating and meter reading services for the Company. For the years ended December 31, 2006, 2005, and 2004, fees for these services paid by the Company to Vectren affiliates totaled $7.4 million, $7.7 million, and $8.6 million, respectively. Amounts charged were market based. Amounts owed to unconsolidated affiliates other than ProLiance totaled less than $0.1 million and $1.2 million at December 31, 2006, and 2005, respectively, and are included in *Accounts payable to affiliated companies* in the Consolidated Balance Sheets.

5. Borrowing Arrangements

Short-Term Borrowings
At December 31, 2005, Utility Holdings has $520 million of short-term borrowing capacity, of which approximately $250 million is available. The Company increased its short-term credit facility in November 2005, by approximately $165 million in response to increased natural gas costs. Utility Holdings' credit facilities are primarily used to support its access to the commercial paper market. See the table below for interest rates and outstanding balances.

	Year Ended December 31,		
(In millions)	2006	2005	2004
Weighted average commercial paper and bank loans outstanding during the year	$ 177.5	$ 193.5	$ 133.2
Weighted average interest rates during the year			
Commercial paper	5.16%	3.42%	1.78%
Bank loans	-	-	2.19%

	At December 31,	
(In millions)	2006	2005
Commercial paper	$ 270.1	$ 226.9
Total short-term borrowings	**$ 270.1**	**$ 226.9**

Table of Contents

Long-Term Debt

Senior unsecured obligations and first mortgage bonds outstanding and classified as long-term by subsidiary follow:

	At December 31,	
(In millions)	2006	2005
UTILITY HOLDINGS		
Senior Unsecured Notes		
2011, 6.625%	$ 250.0	$ 250.0
2013, 5.25%	100.0	100.0
2015, 5.45%	75.0	75.0
2018, 5.75%	100.0	100.0
2031, 7.25%	-	100.0
2035, 6.10%	75.0	75.0
2036, 5.95%	100.0	-
Total VUHI	**700.0**	**700.0**
SIGECO		
First Mortgage Bonds		
2016, 1986 Series, 8.875%	13.0	13.0
2020, 1998 Pollution Control Series B, 4.50%, tax exempt	4.6	4.6
2024, 2000 Environmental Improvement Series A, 4.65%, tax exempt	22.5	22.5
2029, 1999 Senior Notes, 6.72%	80.0	80.0
2030, 1998 Pollution Control Series B, 5.00%, tax exempt	22.0	22.0
2015, 1985 Pollution Control Series A, current adjustable rate 4.06%, tax exempt, auction rate mode, 2006 weighted average: 3.53%	9.8	9.8
2023, 1993 Environmental Improvement Series B, current adjustable rate 4.11%, tax exempt, auction rate mode, 2006 weighted average: 3.74%	22.6	22.6
2025, 1998 Pollution Control Series A, current adjustable rate 4.11%, tax exempt, auction rate mode, 2006 weighted average: 3.08%	31.5	31.5
2030, 1998 Pollution Control Series C, current adjustable rate 4.11%, tax exempt, auction rate mode, 2006 weighted average: 3.20%	22.2	22.2
Total SIGECO	**228.2**	**228.2**
Indiana Gas		
Senior Unsecured Notes		
2007, Series E, 6.54%	6.5	6.5
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	**127.5**	**127.5**
Total long-term debt outstanding	**1,055.7**	**1,055.7**
Current maturities of long-term debt	(6.5)	-
Debt subject to tender	(20.0)	(53.7)
Unamortized debt premium & discount - net	(3.9)	(4.2)
Total long-term debt-net	**$ 1,025.3**	**$ 997.8**

Table of Contents

Utility Holdings 2006 Issuance
In October 2006, Utility Holdings issued $100 million in 5.95% senior unsecured notes due October 1, 2036 (2036 Notes). The 30-year notes were priced at par. The 2036 Notes are guaranteed by Utility Holdings' three public utilities: SIGECO, Indiana Gas, and VEDO. These guarantees are full and unconditional and joint and several. These notes, as well as the timely payment of principal and interest, are insured by a financial guaranty insurance policy issued by Financial Guaranty Insurance Company (FGIC).

The 2036 Notes have no sinking fund requirements, and interest payments are due quarterly. The notes may be called by Utility Holdings, in whole or in part, at any time on or after October 1, 2011, at 100% of principal amount plus accrued interest. During the first and second quarters of 2006, Utility Holdings entered into several interest rate hedges with a $100 million notional amount. Upon issuance of the notes, these instruments were settled resulting in the payment of approximately $3.3 million, which was recorded as a *Regulatory asset* pursuant to existing regulatory orders. The value paid is being amortized as an increase to interest expense over the life of the issue. The proceeds from the sale of the 2036 Notes, settlement of the hedging arrangements, and payments of issuance costs totaled approximately $92.8 million.

Utility Holdings 2005 Issuance
In December 2005, Utility Holdings issued senior unsecured notes with an aggregate principal amount of $150 million in two $75 million tranches. The first tranche was 10-year notes due December 2015, with an interest rate of 5.45% priced at 99.799% to yield 5.47% to maturity (2015 Notes). The second tranche was 30-year notes due December 2035 with an interest rate of 6.10% priced at 99.799% to yield 6.11% to maturity (2035 Notes).

The notes have no sinking fund requirements, and interest payments are due semi-annually. The notes may be called by Utility Holdings, in whole or in part, at any time for an amount equal to accrued and unpaid interest, plus the greater of 100% of the principal amount or the sum of the present values of the remaining scheduled payments of principal and interest, discounted to the redemption date on a semi-annual basis at the Treasury Rate, as defined in the indenture, plus 20 basis points for the 2015 Notes and 25 basis points for the 2035 Notes.

In January and June 2005, Utility Holdings entered into forward starting interest rate swaps with a total notional amount of $75 million. Upon issuance of the debt, the instruments were settled resulting in the receipt of approximately $1.9 million in cash, which was recorded as a regulatory liability pursuant to existing regulatory orders. The value received is being amortized as a reduction of interest expense over the life of the issue maturing December 2035. The net proceeds from the sale of the senior notes and settlement of related hedging arrangements approximated $150 million.

Long-Term Debt Put & Call Provisions
Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. The put or call provisions are not triggered by specific events, but are based upon dates stated in the note agreements, such as when notes are remarketed. During 2006 and 2005, no debt was put to the Company. During 2004 debt totaling $2.5 million was put to the Company. Debt which may be put to the Company during the years following 2006 (in millions) is $20.0 in 2007, zero in 2008, $80.0 in 2009, $10.0 in 2010, $30.0 in 2011, and zero thereafter. Debt that may be put to the Company within one year is classified as *Long-term debt subject to tender* in current liabilities.

Utility Holdings, SIGECO and Indiana Gas Debt Calls
In 2006, the Company called at par $100.0 million of Utility Holdings senior unsecured notes originally due in 2031. In 2005, the Company called at par $49.9 million of Indiana Gas insured quarterly senior unsecured notes originally due in 2030, and in 2004, called at par $20.0 million of Indiana Gas insured quarterly senior unsecured notes originally due in 2015. The notes called in 2006, 2005 and 2004 had stated interest rates of 7.25%, 7.45% and 7.15%,

respectively.

Other Financing Transactions

At December 31, 2005, $53.7 million of SIGECO notes could be put to the Company in March of 2006, the date of their next remarketing. In March of 2006, the notes were successfully remarketed, and are now classified in *Long-term debt.* Prior to the remarketing, the notes had tax-exempt interest rates ranging from 4.75% to 5.00%. After the remarketing, interest rates are reset every seven days using an auction process.

Table of Contents

During 2004, the Company remarketed two first mortgage bonds outstanding at SIGECO. The remarketing effort converted $32.8 million of outstanding fixed rate debt into variable rate debt where interest rates reset weekly. One bond, due in 2023, had a principal amount of $22.8 million and an interest rate of 6%. The other bond, due in 2015, had a principal amount of $10.0 million and an interest rate of 4.3%. These remarketing efforts resulted in the extinguishment of debt and the reissuance of new debt at generally the same par value. These bonds are classified in *Long-term debt.*

Other Company debt totaling $15.0 million in 2004 was retired as scheduled.

Future Long-Term Debt Sinking Fund Requirements & Maturities

The annual sinking fund requirement of SIGECO's first mortgage bonds is 1% 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 2007 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2007 is excluded from *Current liabilities* in the Consolidated Balance Sheets. At December 31, 2006, $739.1 million of SIGECO's utility plant remained unfunded under SIGECO's Mortgage Indenture. SIGECO’s gross utility plant balance subject to the Mortgage Indenture approximated $2.0 billion at December 31, 2006.

Consolidated maturities and sinking fund requirements on long-term debt during the five years following 2006 (in millions) are $6.5 in 2007, zero in 2008 and 2009, and 2010 and $250.0 in 2011.

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. As of December 31, 2006, the Company was in compliance with all financial covenants.

6. Additional Capital Contributions

During the years ended December 31, 2006, 2005, and 2004, the Company has cumulatively received additional capital of $43.1 million from Vectren. Of that total, $40.0 million was funded by Vectren’s nonregulated operations, and $3.1 million was funded by new share issues from Vectren’s dividend reinvestment plan.

7. Commitments & Contingencies

Commitments

Firm purchase commitments for utility and non-utility plant total $64.5 million in 2007, $113.0 million in 2008, $115.0 million in 2009, $70.0 million in 2010 and $28.0 million in 2011.

Legal Proceedings

The Company is party to various legal proceedings arising in the normal course of business. In the opinion of management, there are no legal proceedings pending against the Company that are likely to have a material adverse effect on its financial position or results of operations.

8. Environmental Matters

Clean Air Act

Clean Air Interstate Rule & Clean Air Mercury Rule

In March of 2005 USEPA finalized two new air emission reduction regulations. The Clean Air Interstate Rule (CAIR) is an allowance cap and trade program requiring further reductions in Nitrogen Oxides (NOx) and Sulfur Dioxide (SO_2) emissions from coal-burning power plants. The Clean Air Mercury Rule (CAMR) is an allowance cap and trade program requiring further reductions in mercury emissions from coal-burning power plants. Both sets of regulations require emission reductions in two phases. The first phase deadline for both rules is 2010 (2009 for NOx under CAIR), and the second phase deadline for compliance with the emission reductions required under CAIR is 2015, while the second phase deadline for compliance with the emission reduction requirements of CAMR is 2018. The Company is evaluating compliance options and fully expects to be in compliance by the required deadlines.

Table of Contents

In February 2006, the IURC approved a multi-emission compliance plan filed by the Company's utility subsidiary, SIGECO. Once the plan is implemented, SIGECO's coal-fired plants will be 100% scrubbed for SO_2, 90% scrubbed for NOx, and mercury emissions will be reduced to meet the new mercury reduction standards. The order, as previously agreed to by the OUCC and Citizens Action Coalition, allows SIGECO to recover an approximate 8% return on up to $110 million in capital investments through a rider mechanism which is updated every six months for actual costs incurred. The Company will also recover through a rider its operating expenses, including depreciation, once the equipment is placed into service. The order also stipulates that SIGECO study renewable energy alternatives and include a carbon forecast in future filings with regard to new generation and further environmental compliance plans, among other initiatives. As of December 31, 2006, the Company has made capital investments of approximately $62.2 million related to this environmental requirement.

NOx SIP Call Matter

The Company complied with Indiana's State Implementation Plan (SIP) of the Clean Air Act (the Act). These steps included installation Selective Catalytic Reduction (SCR) systems at Culley Generating Station Unit 3 (Culley), Warrick Generating Station Unit 4, and A. B. Brown Generating Station Units 1 and 2. SCR systems reduce flue gas NOx emissions to atmospheric nitrogen and water using ammonia in a chemical reaction. This technology is known to currently be the most effective method of reducing nitrogen oxide (NOx) emissions where high removal efficiencies are required.

The IURC issued orders that approved:

- the Company's project to achieve environmental compliance by investing in clean coal technology;
- the Company's investment of $258 million in capital costs;
- a mechanism whereby, prior to an electric base rate case, the Company recovers through a rider that is updated every six months, an 8% return on its weighted capital costs for the project; and
- ongoing recovery of operating costs, including depreciation and purchased emission allowances, related to the clean coal technology now that facilities are placed into service.

Culley Generating Station Litigation

During 2003, the U.S. District Court for the Southern District of Indiana entered a consent decree among SIGECO, the Department of Justice (DOJ), and the USEPA that resolved a lawsuit originally brought by the USEPA against SIGECO. The lawsuit alleged violations of the Clean Air Act by SIGECO at its Culley Generating Station for (1) making modifications to a generating station without obtaining required permits, (2) making major modifications to the generating station without installing the best available emission control technology, and (3) failing to notify the USEPA of the modifications.

Under the terms of the agreement, the DOJ and USEPA agreed to drop all challenges of past maintenance and repair activities at the Culley Generating Station. In reaching the agreement, SIGECO did not admit to any allegations in the government's complaint, and SIGECO continues to believe that it acted in accordance with applicable regulations and conducted only routine maintenance on the units. SIGECO entered into this agreement to further its continued commitment to improve air quality and avoid the cost and uncertainties of litigation.

Under the agreement, SIGECO committed to:

- either repower Culley Unit 1 (50 MW) with natural gas and equip it with SCR control technology for further reduction of nitrogen oxide, or cease operation of the unit by December 31, 2006;
- operate the existing SCR control technology recently installed on Culley Unit 3 (287 MW) year round at a lower emission rate than that currently required under the NOx SIP Call, resulting in further nitrogen oxide reductions;
- enhance the efficiency of the existing scrubber at Culley Units 2 and 3 for additional removal of sulphur dioxide emissions;
- install a baghouse for further particulate matter reductions at Culley Unit 3 by June 30, 2007;

- conduct a Sulphuric Acid Reduction Demonstration Project as an environmental mitigation project designed to demonstrate an advance in pollution control technology for the reduction of sulfate emissions; and
- pay a $600,000 civil penalty.

Table of Contents

The Company does not believe that implementation of the settlement will have a material effect on its results of operations or financial condition. The $600,000 civil penalty was expensed and paid during 2003. The Company ceased operation of Culley Unit 1 effective December 31, 2006 and the baghouse, which is included in the $110 million IURC order discussed above, went into service January 1, 2007.

Manufactured Gas Plants

In the past, Indiana Gas, SIGECO, and others operated facilities for the manufacture of gas. Given the availability of natural gas transported by pipelines, these facilities have not been operated for many years. Under currently applicable environmental laws and regulations, those that operated these facilities may now be required to take remedial action if certain byproducts are found above the regulatory thresholds at these sites.

Indiana Gas identified the existence, location, and certain general characteristics of 26 gas manufacturing and storage sites for which it may have some remedial responsibility. Indiana Gas completed a remedial investigation/feasibility study (RI/FS) at one of the sites under an agreed order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. Although Indiana Gas has not begun an RI/FS at additional sites, Indiana Gas has submitted several of the sites to the IDEM's Voluntary Remediation Program (VRP) and is currently conducting some level of remedial activities, including groundwater monitoring at certain sites, where deemed appropriate, and will continue remedial activities at the sites as appropriate and necessary.

In conjunction with data compiled by environmental consultants, Indiana Gas accrued the estimated costs for further investigation, remediation, groundwater monitoring, and related costs for the sites. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, Indiana Gas has recorded costs that it reasonably expects to incur totaling approximately $20.4 million.

The estimated accrued costs are limited to Indiana Gas’ proportionate share of the remediation efforts. Indiana Gas has arrangements in place for 19 of the 26 sites with other potentially responsible parties (PRP), which serve to limit Indiana Gas’ share of response costs at these 19 sites to between 20% and 50%. With respect to insurance coverage, Indiana Gas has received and recorded settlements from all known insurance carriers in an aggregate amount approximating $20.4 million.

In October 2002, SIGECO received a formal information request letter from the IDEM regarding five manufactured gas plants that it owned and/or operated and were not enrolled in the IDEM’s VRP. In response, SIGECO submitted to the IDEM the results of preliminary site investigations conducted in the mid-1990’s. These site investigations confirmed that based upon the conditions known at the time, the sites posed no imminent and/or substantial risk to human health or the environment.

On October 6, 2003, SIGECO filed applications to enter four of the manufactured gas plant sites in IDEM's VRP. The remaining site is currently being addressed in the VRP by another Indiana utility. SIGECO added those four sites into the renewal of the global Voluntary Remediation Agreement that Indiana Gas has in place with IDEM for its manufactured gas plant sites. That renewal was approved by the IDEM on February 24, 2004. On July 13, 2004, 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. While the total costs that may be incurred in connection with addressing these sites cannot be determined at this time, SIGECO has recorded costs that it reasonably expects to incur totaling approximately $7.7 million. With respect to insurance coverage, SIGECO has received and recorded settlements from insurance carriers in an aggregate amount approximating the costs it expects to incur.

Environmental matters related to Indiana Gas’ and SIGECO’s manufactured gas plants have had no material impact on results of operations or financial condition since costs recorded to date approximate PRP and insurance settlement recoveries. 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.

Table of Contents

Jacobsville Superfund Site

On July 22, 2004, the USEPA 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 USEPA 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 USEPA included a 250 acre block of properties surrounding the Jacobsville neighborhood, including Vectren's Wagner Operations Center. Vectren's property has not been named as a source of the lead contamination, nor does the USEPA's soil testing to date indicate that the Vectren property contains lead contaminated soils. Vectren's own soil testing, completed during the construction of the Operations Center, did not indicate that the Vectren property contains lead contaminated soils. At this time, Vectren anticipates only additional soil testing, if required by the USEPA.

Global Climate Change

Global climate change remains a policy issue that is regularly considered for government regulation. If legislation requiring reductions in greenhouses gases is adopted, such regulation could substantially affect both the costs and operating characteristics of the Company’s fossil fuel plants.

9. Rate & Regulatory Matters

Ohio and Indiana Lost Margin Recovery/Conservation Filings

In 2005, the Company filed conservation programs and conservation adjustment trackers in Indiana and Ohio designed to help customers conserve energy and reduce their annual gas bills. The programs would allow the Company to recover costs of promoting the conservation of natural gas through conservation trackers that work in tandem with a lost margin recovery mechanism. This mechanism is designed to allow the Company to recover the distribution portion of its rates from residential and commercial customers based on the level of customer revenues established in each utility’s last general rate case.

Indiana

In December 2006, the IURC approved a settlement agreement between the Company and the OUCC that provides for a 5-year energy efficiency program to be implemented. The order allows the Company’s Indiana utilities to recover the costs of promoting the conservation of natural gas through conservation trackers that work in tandem with a lost margin recovery mechanism that would provide for recovery of 85% of the difference between revenues actually collected by the Company and the revenues approved in the Company’s most recent rate case. The order was implemented in the North service territory in December 2006 and will be implemented in South’s service territory after its next general rate case (see below.) While most expenses associated with these programs are recoverable, in the first program year, the Company is required to fund $1.5 million in program costs without recovery.

Ohio

In September 2006, the PUCO approved a conservation proposal that would implement a decoupling approach, including a related conservation program, for the Company’s Ohio operations. The PUCO decision was issued following a hearing process and the submission of a settlement by the Company, the Ohio Consumer Counselor (OCC) and the Ohio Partners for Affordable Energy (OPAE). That settlement was contested by the PUCO Staff. In the decision the PUCO addressed decoupling by approving a two year, $2 million total, low-income conservation program to be funded by the Company, as well as a sales reconciliation rider intended to be a recovery mechanism for the difference between the weather normalized revenues actually collected by the company and the revenues approved by the PUCO in the Company’s most recent rate case. The decision produced an outcome that was different from the settlement. Following the decision, the Company and the OPAE advised the PUCO that they would accept the outcome even though it differed from the terms of the settlement. The OCC sought rehearing of the decision, which was denied in December, and thereafter the OCC advised the PUCO that the OCC was withdrawing from the settlement. At that point the OCC also initiated the process for appealing the PUCO's September and December decisions to the Ohio Supreme Court. Thereafter, the Company, the OPAE and the PUCO Staff advised the PUCO that they accepted the terms provided in the September decision, as affirmed by the December rehearing decision. Since that time there have been a number of procedural filings by the parties and presently the company is awaiting a further decision from the PUCO. The company believes that the PUCO had the necessary legal basis for its decisions and thus should confirm the outcome provided in the September decision.

Table of Contents

Vectren South (Southern Indiana Gas & Electric) Base Rate Filings

On September 1, 2006, Vectren South filed petitions with the IURC to adjust its electric and gas base rates in its South service territory. The electric petition requests an increase of $76.7 million in base rates to recover the nearly $120 million additional investment in electric utility infrastructure since its last base rate increase in 1995, which is not currently included in rates charged to customers. The increase in rates also is required to support system growth, maintenance, reliability and recovery of costs deferred under previous IURC orders. The gas petition seeks to increase its gas base (non-gas cost) rates by $10.4 million to cover the ongoing costs of operating and maintaining its natural gas distribution and storage system. Based upon the timelines prescribed by the IURC at the start of these proceedings, decisions in each case are expected to be issued in the late summer of 2007. The initial public hearings in both cases have been conducted. On January 30, 2007, the OUCC filed testimony in the gas rate case proposing an increase of $5.1 million.

Integrated Gasification Combined Cycle (IGCC) Certificate of Public Convenience and Necessity

On September 7, 2006, Vectren Energy Delivery of Indiana and Duke Energy Indiana, Inc. filed with the IURC a joint petition for a Certificate of Public Convenience and Necessity (CPCN) for the construction of new electric capacity. Specifically, Vectren requested the IURC approve its construction and ownership of up to 20% of an IGCC project. Vectren's CPCN filing also seeks timely recovery of its 20% portion of the project's construction costs as well as operation and maintenance costs and additional incentives available for the construction of clean coal technology. Initial studies of plant design have already begun, and if the project moves forward as currently designed, plant construction is expected to begin in 2007 and continue through 2011.

Weather Normalization

On October 5, 2005, the IURC approved the establishment of a normal temperature adjustment (NTA) mechanism for Vectren Energy Delivery of Indiana. The OUCC had previously entered into a settlement agreement with Vectren Energy Delivery of Indiana providing for the NTA. The NTA affects the Company’s Indiana regulated residential and commercial natural gas customers and should mitigate weather risk in those customer classes during the October to April heating season. These Indiana customer classes represent approximately 60-65% of the Company’s total natural gas heating load.

The NTA mechanism will mitigate volatility in distribution charges created by fluctuations in weather by lowering customer bills when weather is colder than normal and increasing customer bills when weather is warmer than normal. The NTA has been applied to meters read and bills rendered after October 15, 2005. Each subsequent monthly bill for the seven-month heating season will be adjusted using the NTA.

The order provides that the Company will make, on a monthly basis, a commitment of $125,000 to a universal service fund program or other low-income assistance program for the duration of the NTA or until a general rate case.

Rate structures in the Company’s Indiana electric territory and Ohio gas territory do not include weather normalization-type clauses.

Gas Utility Base Rate Settlements in 2004 and 2005

On June 30, 2004, the IURC approved a $5.7 million base rate increase for SIGECO’s gas distribution business, and on November 30, 2004, approved a $24 million base rate increase for Indiana Gas’ gas distribution business. On April 13, 2005, the PUCO approved a $15.7 million base rate increase for VEDO’s gas distribution business. The base rate change in SIGECO’s service territory was implemented on July 1, 2004; the base rate change in Indiana Gas’ service territory was implemented on December 1, 2004; and the base rate change in VEDO’s service territory was implemented on April 14, 2005.

The orders also permit SIGECO and Indiana Gas to recover the on-going costs to comply with the Pipeline Safety Improvement Act of 2002. The Pipeline Safety Improvement Tracker provides for the recovery of incremental non-capital dollars, capped at $750,000 the first year and $500,000 thereafter for SIGECO and $2.5 million per year for Indiana Gas. Any costs incurred in excess of these annual caps are to be deferred for future recovery. VEDO’s new base rates provide for the recovery of some level of on-going costs to comply with the Pipeline Safety Improvement Act of 2002.

Table of Contents

MISO

Since February 2002 and with the IURC's approval, the Company has been a member of the Midwest Independent System Operator, Inc. (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. Pursuant to an order from the IURC received in December 2001, certain MISO startup costs (referred to as Day 1 costs) have been deferred for future recovery in the next general rate case, which was filed in 2006.

On April 1, 2005, the MISO energy market commenced operation (the Day 2 energy market). As a result of being a market participant, the Company now bids its owned generation into the Day Ahead and Real Time markets and procures power for its retail customers at Locational Marginal Pricing (LMP) as determined by the MISO market.

On June 1, 2005, Vectren, together with three other Indiana electric utilities, received regulatory authority from the IURC that allows recovery of fuel related costs and deferral of other costs associated with the Day 2 energy market. The order allows fuel related costs to be passed through to customers in Vectren's existing fuel cost recovery proceedings. The other non-fuel and MISO administrative related costs are to be deferred for recovery as part of the next electric general rate case proceeding, which was filed in 2006. During 2006, the IURC reaffirmed the definition of certain costs as fuel related; the company is following those guidelines.

As a result of MISO's operational control over much of the Midwestern electric transmission grid, including SIGECO's transmission facilities, SIGECO's continued ability to import power, when necessary, and export power to the wholesale market has been, and may continue to be, impacted. Given the nature of MISO's policies regarding use of transmission facilities, as well as ongoing FERC initiatives and uncertainties around Day 2 energy market operations, it is difficult to predict near term operational impacts. However, as stated above, it is believed that MISO's regional operation of the transmission system will ultimately lead to reliability improvements.

The potential need to expend capital for improvements to the transmission system, both to SIGECO's facilities as well as to those facilities of adjacent utilities, over the next several years will become more predictable as MISO completes studies related to regional transmission planning and improvements. Such expenditures may be significant.

Gas Cost Recovery (GCR) Audit Proceedings

On June 14, 2005, the PUCO issued an order disallowing the recovery of approximately $9.6 million of gas costs relating to the two-year audit period ended November 2002. That audit period provided the PUCO staff its initial review of the portfolio administration arrangement between VEDO and ProLiance. The disallowance includes approximately $1.3 million relating to pipeline refunds and penalties and approximately $4.5 million of costs for winter delivery services purchased by VEDO to ensure reliability over the two-year period. The PUCO also held that ProLiance should have credited to VEDO an additional $3.8 million more than credits actually received for the right to use VEDO's gas transportation capacity periodically during the periods when it was not required for serving VEDO's customers. The PUCO also directed VEDO to either submit its receipt of portfolio administration services to a request for proposal process or to in-source those functions. During 2003, the Company recorded a reserve of $1.1 million for this matter. An additional pretax charge of $4.1 million was recorded in *Cost of gas sold* in 2005. The reserve reflects management's assessment of the impact of the PUCO decisions, an estimate of any current impact that decision may have on subsequent audit periods, and an estimate of a sharing in any final disallowance by Vectren's partner in ProLiance.

VEDO filed its request for rehearing on July 14, 2005, and on August 10, 2005, the PUCO granted rehearing to further consider the $3.8 million portfolio administration issue and all interest on the findings, but denied rehearing on all other aspects of the case. On October 7, 2005, the Company filed an appeal with the Ohio Supreme Court requesting that the $4.5 million disallowance related to the winter delivery service issue be reversed. On December 21, 2005, the PUCO granted in part VEDO's rehearing request, and reduced the $3.8 million disallowance related to portfolio administration to $1.98 million. The Company has appealed the $1.98 million disallowance to the Ohio Supreme Court as well. Briefings of all matters and oral arguments were completed in November 2006, and the parties are awaiting the Court's ruling.

Table of Contents

With respect to the most recent GCR audit covering the period of November 1, 2002 through October 31, 2005, the PUCO staff recommended a disallowance of approximately $830,000 related solely to the retention of a reserve margin for the winter of 2002/2003. The Company had previously reserved for the possible disallowance given the June 2005 PUCO order but has contested the disallowance. The PUCO will issue a decision on that issue in 2007.

As a result of the June 2005 PUCO order, the Company has established an annual bidding process for VEDO's gas supply and portfolio administration services. Since November 1, 2005, the Company has used a third party provider for these services.

10. Derivatives & Other Financial Instruments

Accounting Policy for Derivatives

The Company executes 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. The Company accounts for its derivative contracts in accordance with SFAS 133, "Accounting for Derivatives" and its related amendments and interpretations. In most cases, SFAS 133 requires a derivative to be recorded on the balance sheet as an asset or liability measured at its market value and that a change in the derivative's market value be 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, it is exempted from mark-to-market accounting. Otherwise, energy contracts and financial contracts that are derivatives 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. 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 SFAS 71. 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 or, as an adjustment to the underlying's basis for fair value hedges. The ineffective portion of hedging arrangements is marked-to-market through earnings. The offset to contracts affected by SFAS 71 are marked-to-market as a regulatory asset or liability. Market value for derivative contracts is determined using quoted market prices from independent sources. Following is a more detailed discussion of the Company's use of mark-to-market accounting in five primary areas: asset optimization, SO_2 emission allowance risk management, natural gas procurement, and interest rate management.

Asset Optimization

Periodically, generation capacity is in excess of that needed to serve native load and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. These optimization strategies involve the sale of excess generation into the MISO day ahead and real-time markets. As part of these strategies, the Company may execute energy contracts that are integrated with portfolio requirements around power supply and delivery and are short-term purchase and sale transactions that expose the Company to limited market risk. Contracts with counter-parties subject to master netting arrangements are presented net in the Consolidated Balance Sheets. Asset optimization contracts that are derivatives are recorded at market value.

At December 31, 2006, no asset optimization contracts remained in *Prepayments & other current assets.* At December 31, 2005, asset optimization contracts recorded at market value approximated $1.3 million of *Prepayments & other current assets*.

The proceeds received and paid upon settlement of both purchase and sale contracts along with changes in market value of open contracts that are derivatives are recorded in *Electric utility revenues*. Net revenues from asset optimization activities totaled $29.8 million in 2006, $38.0 million in 2005, and $23.8 million in 2004.

Table of Contents

SO_2 Emission Allowance Risk Management
The Company's wholesale power marketing operations are exposed to price risk associated with SO_2 emission allowances. Recently, the price for emission allowances has become more volatile. To hedge this risk, the Company executed call options in 2004 and 2005 to hedge wholesale emission allowance utilization in future periods. The Company designated and documented these derivatives as cash flow hedges. At December 31, 2006, a deferred gain of approximately $1.4 million remains in *Accumulated other comprehensive income* comprehensive income which will be recognized in earnings as emission allowances are utilized. Hedge ineffectiveness totaled $0.2 million of expense in 2006 and $0.8 million of expense in 2005. No SO_2 emission allowance hedges are outstanding as of December 31, 2006.

Natural Gas Procurement Activity
The Company's regulated operations have limited exposure to commodity price risk for purchases and sales of natural gas and electricity for retail customers due to current Indiana and Ohio regulations which, subject to compliance with those regulations, allow for recovery of such purchases through natural gas and fuel cost adjustment mechanisms. Although Vectren's regulated operations are exposed to limited commodity price risk, volatile natural gas prices can result in higher working capital requirements, increased expenses including unrecoverable interest costs, uncollectible accounts expense, and unaccounted for gas, and some level of price- sensitive reduction in volumes sold. The Company mitigates these risks by executing derivative contracts that manage the price volatility of forecasted natural gas purchases. These contracts are subject to regulation which allows for reasonable and prudent hedging costs to be recovered through rates. When regulation is involved, SFAS 71 controls when the offset to mark-to-market accounting is recognized in earnings.

At December 31, 2006 and 2005, the market values of these contracts were not significant.

Interest Rate Management
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 has used interest rate swaps and treasury locks to hedge forecasted debt issuances and other interest rate swaps to manage interest rate exposure. Hedging instruments are recorded at market value. Changes in market value, when effective, are recorded in *Accumulated other comprehensive income* for cash flow hedges, as an adjustment to the outstanding debt balance for fair value hedges, or as regulatory asset/liability when regulation is involved. Amounts are recorded to interest expense as settled.

Interest rate swaps hedging the fair value of fixed-rate debt with a total notional amount of $17.5 million are outstanding. The fair value liability associated with those swaps was $0.3 million at December 31, 2006 and $0.4 million at December 31, 2005. At December 31, 2006, an approximate $2.8 million net regulatory liability remains. Of that net liability, $0.6 million will be reclassified to earnings in 2007, $0.7 million was reclassified to earnings in 2006, and $0.6 million was reclassified to earnings during both 2005 and 2004.

Fair Value of Other Financial Instruments
The carrying values and estimated fair values of the Company's other financial instruments follow:

	At December 31,			
	2006		2005	
In millions	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long-term debt	$ 1,055.7	$ 1,072.6	$ 1,055.7	$ 1,105.2
Short-term borrowings	270.1	270.1	226.9	226.9

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, its carrying amount approximates its fair value.

Table of Contents

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.

11. Additional Balance Sheet & Operational Information

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

	At December 31,			
(In millions)	2006		2005	
Prepaid gas delivery service	$	66.2	$	69.3
Prepaid taxes		20.7		27.1
Deferred income taxes		3.5		-
Other prepayments & current assets		12.8		20.8
Total prepayments & other current assets	**$**	**103.2**	**$**	**117.2**

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

	At December 31,			
(In millions)	2006		2005	
Refunds to customers & customer deposits	$	42.3	$	36.4
Accrued taxes		28.3		31.5
Accrued interest		15.5		16.2
Deferred income taxes		-		7.6
Accrued salaries & other		29.7		38.7
Total accrued liabilities	**$**	**115.8**	**$**	**130.4**

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

	Year Ended December 31,					
(In millions)	2006		2005		2004	
AFUDC & capitalized interest	$	4.8	$	2.5	$	4.6
Interest income		0.7		0.6		0.5
Other income		2.1		2.8		2.0
Total other – net	**$**	**7.6**	**$**	**5.9**	**$**	**7.1**

12. 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 into 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 marketing operations. The Company cross manages its regulated operations as separated between Energy Delivery, which includes the gas and electric transmission and distribution functions, and Power Supply, which includes the power generating and marketing operations. In total, regulated operations supply natural gas and /or electricity to over one million customers. Net income is the measure of profitability used by management for all operations. In total, the Utility Holdings has three operating segments of as defined by SFAS 131 “Disclosure About Segments of an Enterprise and Related Information” (SFAS 131).

Table of Contents

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

	Year Ended December 31,		
(In millions)	2006	2005	2004
Revenues			
Gas Utility Services	$ 1,232.5	$ 1,359.7	$ 1,126.2
Electric Utility Services	422.2	421.4	371.3
Other Operations	36.6	36.1	32.9
Eliminations	(34.8)	(35.4)	(32.4)
Total revenues	$ 1,656.5	$ 1,781.8	$ 1,498.0
Profitability Measure - Net Income			
Gas Utility Services	$ 41.5	$ 34.7	$ 28.1
Electric Utility Services	41.6	50.4	47.9
Other Operations	8.3	10.0	7.1
Total net income	$ 91.4	$ 95.1	$ 83.1
Amounts Included in Profitability Measures			
Depreciation & Amortization			
Gas Utility Services	$ 67.6	$ 64.9	$ 57.0
Electric Utility Services	61.8	56.9	53.3
Other Operations	21.9	19.5	17.5
Total depreciation & amortization	$ 151.3	$ 141.3	$ 127.8
Interest Expense			
Gas Utility Services	$ 40.7	$ 40.2	$ 41.4
Electric Utility Services	28.6	23.7	21.3
Other Operations	8.2	6.0	4.7
Total interest expense	$ 77.5	$ 69.9	$ 67.4
Equity in Earnings of Unconsolidated Affiliates			
Other Operations	$ -	$ -	$ 0.2
Income Taxes			
Gas Utility Services	$ 22.6	$ 22.3	$ 17.5
Electric Utility Services	25.3	33.5	30.8
Other Operations	(0.2)	1.7	4.8
Total income taxes	$ 47.7	$ 57.5	$ 53.1
Capital Expenditures			
Gas Utility Services	$ 76.8	$ 81.0	$ 89.1
Electric Utility Services	156.8	100.0	150.6
Other Operations	24.8	29.9	27.9
Non-cash costs & changes in accruals	(8.4)	6.9	(21.4)
Total capital expenditures	$ 250.0	$ 217.8	$ 246.2

Table of Contents

(In millions)	At December 31, 2006	2005
Assets		
Utility Group		
Gas Utility Services	$ 1,953.6	$ 2,030.8
Electric Utility Services	1,277.6	1,176.0
Other Operations	225.9	188.9
Eliminations	(16.3)	(4.5)
Total assets	$ 3,440.8	$ 3,391.2

13. Subsidiary Guarantor and Consolidating Information

The Company's three operating utility companies, SIGECO, Indiana Gas, and VEDO are guarantors of Utility Holdings' $520 million in short-term credit facilities, of which $270.1 million is outstanding at December 31, 2006, and Utility Holdings' $700.0 million unsecured senior notes outstanding at December 31, 2006. 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 a tax sharing agreement, consolidating tax effects are reflected at the parent level. Pursuant to Item 3-10 of Regulation S-X, disclosure of the results of operations and balance sheets of the subsidiary guarantors 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.

Consolidating Statement of Income for the year ended December 31, 2006 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 1,232.5	$ -	$ -	$ 1,232.5
Electric utility	422.2	-	-	422.2
Other	-	36.6	(34.8)	1.8
Total operating revenues	**1,654.7**	**36.6**	**(34.8)**	**1,656.5**
OPERATING EXPENSES				
Cost of gas sold	841.5	-	-	841.5
Cost of fuel & purchased power	151.5	-	-	151.5
Other operating	275.5	(4.4)	(32.1)	239.0
Depreciation & amortization	129.4	21.5	0.4	151.3
Taxes other than income taxes	63.0	1.1	0.1	64.2
Total operating expenses	1,460.9	18.2	(31.6)	1,447.5
OPERATING INCOME	**193.8**	**18.4**	**(3.2)**	**209.0**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	-	83.2	(83.2)	-
Other – net	3.7	42.6	(38.7)	7.6
Total other income (expense)	3.7	125.8	(121.9)	7.6
Interest expense	66.4	53.0	(41.9)	77.5
INCOME BEFORE INCOME TAXES	**131.1**	**91.2**	**(83.2)**	**139.1**
Income taxes	47.9	(0.2)	-	47.7
NET INCOME	**$ 83.2**	**$ 91.4**	**$ (83.2)**	**$ 91.4**

Table of Contents

Consolidating Statement of Income for the year ended December 31, 2005 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 1,359.7	$ -	$ -	$ 1,359.7
Electric utility	421.4	-	-	421.4
Other	-	36.1	(35.4)	0.7
Total operating revenues	**1,781.1**	**36.1**	**(35.4)**	**1,781.8**
OPERATING EXPENSES				
Cost of gas sold	973.3	-	-	973.3
Cost of fuel & purchased power	144.1	-	-	144.1
Purchased electric energy		-		
Other operating	274.4	0.1	(33.2)	241.3
Depreciation & amortization	121.7	19.3	0.3	141.3
Taxes other than income taxes	64.7	0.4	0.1	65.2
Total operating expenses	1,578.2	19.8	(32.8)	1,565.2
OPERATING INCOME	**202.9**	**16.3**	**(2.6)**	**216.6**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	-	85.3	(85.3)	-
Other – net	4.3	37.8	(36.2)	5.9
Total other income (expense)	4.3	123.1	(121.5)	5.9
Interest expense	64.4	42.9	(37.4)	69.9
INCOME BEFORE INCOME TAXES	**142.8**	**96.5**	**(86.7)**	**152.6**
Income taxes	57.5	1.4	(1.4)	57.5
NET INCOME	**$ 85.3**	**$ 95.1**	**$ (85.3)**	**$ 95.1**

Consolidating Statement of Income for the year ended December 31, 2004 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
OPERATING REVENUES				
Gas utility	$ 1,126.2	$ -	$ -	$ 1,126.2
Electric utility	371.3	-	-	371.3
Other	-	32.9	(32.4)	0.5
Total operating revenues	**1,497.5**	**32.9**	**(32.4)**	**1,498.0**
OPERATING EXPENSES				
Cost of gas sold	778.5	-	-	778.5
Cost of fuel & purchased power	116.8	-	-	116.8
Purchased electric energy		-		
Other operating	249.8	1.1	(30.5)	220.4
Depreciation & amortization	110.1	17.5	0.2	127.8
Taxes other than income taxes	57.5	0.6	0.1	58.2
Total operating expenses	1,312.7	19.2	(30.2)	1,301.7
OPERATING INCOME	**184.8**	**13.7**	**(2.2)**	**196.3**
OTHER INCOME (EXPENSE)				
Equity in earnings of consolidated companies	-	75.9	(75.9)	-

Equity in earnings/losses of unconsolidated affiliates		-		0.2		-		0.2
Other – net		5.8		35.4		(34.1)		7.1
Total other income (expense)		5.8		111.5		(110.0)		7.3
Interest expense		62.9		37.5		(33.0)		67.4
INCOME BEFORE INCOME TAXES		**127.7**		**87.7**		**(79.2)**		**136.2**
Income taxes		51.8		4.6		(3.3)		53.1
NET INCOME	**$**	**75.9**	**$**	**83.1**	**$**	**(75.9)**	**$**	**83.1**

Table of Contents

Consolidating Statement of Cash Flows for the year ended December 31, 2006 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	**$ 279.9**	**$ 6.2**	**$ -**	**$ 286.1**
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from:				
Additional capital contribution	40.0	20.0	(40.0)	20.0
Long-term debt - net of issuance costs & hedging proceeds	228.9	92.8	(228.9)	92.8
Requirements for:				
Retirement of long-term debt, including premiums paid	(96.7)	(100.0)	96.7	(100.0)
Dividends to parent	(75.4)	(75.4)	75.4	(75.4)
Redemption of preferred stock of subsidiary	-	-	-	-
Net change in short-term borrowings, including from other Vectren companies	(156.5)	43.2	156.5	43.2
Net cash flows from financing activities	**(59.7)**	**(19.4)**	**59.7**	**(19.4)**
CASH FLOWS FROM INVESTING ACTIVITIES				
Proceeds from:				
Consolidated subsidiary distributions	-	75.4	(75.4)	-
Other investing activities	-	0.1	-	0.1
Requirements for:				
Capital expenditures, excluding AFUDC equity	(225.5)	(24.5)	-	(250.0)
Consolidated subsidiary investments	-	(172.2)	172.2	-
Net change in notes receivable from other Vectren companies	-	156.5	(156.5)	-
Net cash flows from investing activities	**(225.5)**	**35.3**	**(59.7)**	**(249.9)**
Net (decrease) increase in cash & cash equivalents	(5.3)	22.1	-	16.8
Cash & cash equivalents at beginning of period	11.0	0.7	-	11.7
Cash & cash equivalents at end of period	$ 5.7	$ 22.8	$ -	$ 28.5

Consolidating Statement of Cash Flows for the year ended December 31, 2005 (in millions):

	Subsidiary Guarantors	Parent Company	Eliminations	Consolidated
NET CASH FLOWS FROM OPERATING ACTIVITIES	**$ 224.0**	**$ 41.8**	**$ -**	**$ 265.8**
CASH FLOWS FROM FINANCING ACTIVITIES				

Proceeds from:				
Additional capital contribution	125.0	20.0	(125.0)	20.0
Long-term debt - net of issuance costs & hedging proceeds	-	150.0	-	150.0
Requirements for:				
Retirement of long-term debt, including premiums paid	(49.9)	-	-	(49.9)
Dividends to parent	(80.7)	(80.7)	80.7	(80.7)
Redemption of preferred stock of subsidiary	(0.1)	-	-	(0.1)
Net change in short-term borrowings, including from other				