

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

FORM 10-K

(Mark One)



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

For the fiscal year ended December 31, 2002

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: **1-3553**

**SOUTHERN INDIANA GAS AND
ELECTRIC COMPANY**

(Exact name of registrant as specified in its charter)

INDIANA

(State or other jurisdiction of incorporation or organization)

35-0672570

(IRS Employer Identification No.)

20 N.W. Fourth Street, Evansville, Indiana

(Address of principal executive offices)

47708

(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

None

Name of each exchange on which registered

None

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

Title of each class

None

Name of each exchange on which registered

None

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 ☒. No ____.

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes _____. No ☒.

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 28, 2002 was zero. All shares outstanding of the Registrant's common stock were held by Vectren Corporation through its wholly owned subsidiary, Vectren Utility Holdings, Inc.

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
Class

20,785,007
Number of Shares

March 15, 2003
Date

Omission of Information by Certain Wholly Owned Subsidiaries

The Registrant is a wholly owned subsidiary of Vectren Utility Holdings, Inc. 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

FASB: Financial Accounting Standards Board

IURC: Indiana Utility Regulatory Commission

MCF / BCF: millions / billions of cubic feet

MMDth: millions of dekatherms

MMBTU: millions of British thermal units

Mva: megavolt amperes

MW: megawatts

GWh: millions of megawatt hours (gigawatt hour)

NOx: nitrogen oxide

OUCC: Indiana Office of the Utility Consumer Counselor

SFAS: Statement of Financial Accounting Standards

USEPA: United States Environmental Protection Agency

Throughput: combined gas sales and gas transportation volumes

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(A) – Omitted or amended as the Registrant is a wholly-owned subsidiary of Vectren Utility Holdings, Inc. 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 free of charge, including those of its wholly owned subsidiaries, 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:
P.O. Box 209
Evansville, Indiana 47702-0209

Phone Number:
(812) 491-4000

Investor Relations Contact:
Steven M. Schein
Vice President, Investor Relations
Sschein@vectren.com

PART I

ITEM 1. BUSINESS

Description of the Business

Southern Indiana Gas and Electric Company (the Company or SIGECO), an Indiana corporation, provides electric generation, transmission, and distribution services to 8 counties in southwestern Indiana, including counties surrounding Evansville, and participates in the wholesale power market. The Company also provides natural gas distribution and transportation services to 10 counties in southwestern Indiana, including counties surrounding Evansville. SIGECO is a direct subsidiary of Vectren Utility Holdings, Inc. (VUHI). VUHI is a direct, wholly owned subsidiary of Vectren Corporation (Vectren).

Vectren, an Indiana corporation, is an energy and applied technology holding company headquartered in Evansville, Indiana. Vectren was organized on June 10, 1999 solely for the purpose of effecting the merger of Indiana Energy, Inc. (Indiana Energy) and SIGCORP, Inc. (SIGCORP). On March 31, 2000, the merger of Indiana Energy with SIGCORP and into Vectren was consummated with a tax-free exchange of shares and has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 "Business Combinations."

Vectren's wholly owned subsidiary, VUHI, serves as the intermediate holding company for its three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), formerly a wholly owned subsidiary of Indiana Energy, SIGECO, formerly a wholly owned subsidiary of SIGCORP, and the Ohio operations, a utility jointly owned by Indiana Gas and Vectren Energy Delivery of Ohio, Inc. (VEDO). Both Vectren and VUHI are exempt from registration pursuant to Section 3(a)(1) and 3(c) of the Public Utility Holding Company Act of 1935.

The narrative description of the business, competition and personnel sections were intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

ITEM 2. PROPERTIES

Electric Utility Services

SIGECO's installed generating capacity as of December 31, 2002, was rated at 1,351 MW. SIGECO's coal-fired generating facilities are: the Brown Station with 500 MW of capacity, located in Posey County approximately eight miles east of Mt. Vernon, Indiana; the Culley Station with 406 MW of 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: the 80 MW Brown 3 Gas Turbine 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, 50MW and Broadway Avenue Unit 2, 65MW); two Northeast Gas Turbines located northeast of Evansville in Vanderburgh County, Indiana with a combined capacity of 20 MW; and a new 80MW turbine also located at the Brown station (Brown Unit 4) placed into service in 2002. 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.

SIGECO's transmission system consists of 829 circuit miles of 138,000 and 69,000 volt lines. The transmission system also includes 27 substations with an installed capacity of 4,221.2 megavolt amperes (Mva). The electric distribution system includes 3,212 pole miles of lower voltage overhead lines and 275 trench miles of conduit containing 1,541 miles of underground distribution cable. The distribution system also includes 95 distribution substations with an installed capacity of 1,939.5 Mva and 50,030 distribution transformers with an installed capacity of 2,352.3 Mva.

SIGECO owns utility property outside of Indiana approximating eight 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.

Gas Utility Services

The Company 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 8.7 BCF of gas with delivery capabilities of 124,748 MCF per day. In addition to its owned storage and daily delivery capabilities, the Company contracts for a maximum of 0.5 BCF of gas availability across various pipelines with a delivery capability of 18,753 MCF per day. The Company's gas delivery system includes 2,996 miles of distribution and transmission mains, all of which are located in Indiana.

Property Serving as Collateral

The Company's properties are subject to the lien of the First Mortgage Indenture dated as of April 1, 1932 between the Company 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 or results of operations. See Note 10 of its financial statements included in Item 8 Financial Statements and Supplementary Data regarding the Clean Air Act and related legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO VOTE OF SECURITY HOLDERS

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Price

All of the outstanding shares of the Company's common stock are owned by VUHI at December 31, 2002. The Company's common stock is not publicly traded.

As of December 31, 2002, there are no outstanding options or warrants to purchase the Company's common stock or securities convertible into the Company's common stock. Additionally, the Company has no plans to publicly offer any of its common equity.

Dividends Paid to Parent

During 2002, the Company paid dividends to its parent company of \$10.3 million, \$11.6 million, \$11.6 million, and \$11.6 million in the first, second, third, and fourth quarters, respectively.

During 2001, the Company paid dividends to its parent company of \$8.6 million, \$7.7 million, \$7.7 million, and \$14.9 million in the first, second, third, and fourth quarters, respectively.

On January 29, 2003, the board of directors declared a dividend of \$10.9 million, payable to its parent company on March 1, 2003.

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

ITEM 6. SELECTED FINANCIAL DATA

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

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

Pursuant to General Instructions I(2)(a) of Form 10-K, the following analysis of the results of operations is presented in lieu of Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis should be read in conjunction with the financial statements and notes thereto. As discussed in Note 3 in the financial statements, subsequent to the issuance of the Company's 2001 financial statements, the Company's management determined that previously issued financial statements should be restated. As a result, the Company has restated its 2001 and 2000 financial statements and has increased reported retained earnings as of January 1, 2000 by \$2.9 million. The restatement had the effect of decreasing net income for 2001 and 2000 by approximately \$1.8 million and \$0.7 million, respectively. Note 3 to the financial statements includes a summary of the significant effects of the restatement. The effect of the restatement on quarterly results, including previously reported 2002 quarterly information, is discussed in Note 3 and Note 17. The following discussion and analysis gives effect to the restatement.

Results of Operations

In 2002, net income applicable to common shareholder was \$59.3 million, an increase of \$18.6 million when compared to 2001, as restated. The year ended December 31, 2001 included nonrecurring merger, integration, and restructuring costs and other nonrecurring items totaling \$4.0 million after tax. In addition to the nonrecurring 2001 items, the increase reflects improved margins and lower operating costs. These resulted from favorable weather and a return to lower gas prices and the related reduction in costs incurred in 2001.

In 2001, net income applicable to common shareholder was \$40.7 million. Net income applicable to common shareholder increased \$1.3 million due primarily to lower nonrecurring items incurred in 2001 compared to 2000. Nonrecurring merger and integration costs in 2000 totaled \$11.0 million after tax. Before nonrecurring items, net income applicable to common shareholder decreased \$5.7 million primarily due to extraordinarily high gas costs early in 2001 that unfavorably impacted margins and operating costs including uncollectible accounts expense and interest; heating weather that was 10% warmer than the prior year; and decreased margin from firm and non-firm wholesale customers, reflecting a weakened national economy.

Restatement of Previously Reported Results

The Company identified adjustments that, in the aggregate, reduced previously reported 2001 earnings by approximately \$1.8 million after tax, decreased previously reported 2000 results by approximately \$0.7 million after tax, and increased retained earnings as of January 1, 2000 by \$2.9 million after tax. Adjustments were also made to previously reported 2002 quarterly results. In addition to adjustments affecting previously reported net income, other reclassifications were made to the previously reported 2001 and 2000 results to conform with the 2002 presentation.

Previously Reported 2001 and 2000 Net Income Adjustments

The Company determined that \$3.3 million (\$2.0 million after tax) of gas costs were improperly recorded as recoverable gas costs due from customers. The error related primarily to the accounting for natural gas inventory and resulted in an overstatement of 2001 earnings.

The Company also identified an accounting error related to certain employee benefit and other related costs that are routinely accumulated on the balance sheet and systematically cleared to operating expense and capital projects. Because of inadequate loading rates, these costs were not fully cleared to operating expense and capital projects in 2001. As a result, 2001 earnings were overstated by \$1.5 million (\$0.9 million after tax).

The accounting for certain wholesale power marketing contracts was modified to comply with SFAS 133, which became effective on January 1, 2001. The cumulative effect at adoption was decreased by \$2.8 million after tax. This change was offset substantially by an increase in electric margins throughout 2001.

Originally reflected in 2001, the Company also reflected a correction of the year 2000 overstatement of electric revenue totaling \$2.4 million (\$1.5 million after tax), now reflected in 2000 as discussed below. The Company identified other reconciliation errors and other errors related to the recording of estimates that were not significant, either individually or in the aggregate. As a result of these additional items, 2001 earnings were reduced by \$0.6 million (\$0.4 million after tax).

The Company also determined that certain billings and collections had been improperly recorded in 2000, resulting in an overstatement of electric revenue by \$2.4 million (\$1.5 million after tax). Other errors were identified that increased 2000 earnings by \$1.3 million (\$0.8 million after tax). The impact of the restatement of results for the year ended 2000 is a reduction to pre-tax income and net income of \$1.1 million and \$0.7 million, respectively.

Previously Reported 2002 Quarterly Net Income Adjustments

As previously reported, in the second quarter of 2002 the Company recorded \$5.2 million (\$3.2 million after tax) of carrying costs for DSM programs pursuant to existing IURC orders and based on an improved regulatory environment. During the audit of the three years ended December 31, 2002, management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in 2002 quarterly results were reversed and reflected in common shareholder's equity as of January 1, 2000. In addition, the Company identified other adjustments that were not significant, either individually or in the aggregate that increased previously reported 2002 quarterly pre-tax and after tax earnings by approximately \$0.2 million and \$0.1 million after tax, respectively. The cumulative impact from these adjustments reduced previously reported earnings for the nine months ended September 30, 2002 by approximately \$3.3 million.

Beginning Retained Earnings Adjustments

In addition to the adjustment of DSM costs above, the Company identified other errors that were not significant, either individually or in the aggregate that relate to years prior to 2000 resulting in a cumulative net increase of \$2.9 million in retained earnings as of January 1, 2000.

Other Balance Sheet Adjustments

Certain reclassifications were made to reflect separate Company current and deferred income taxes are included in Vectren's consolidated tax position. These reclassifications are the principal adjustments to intercompany receivables and payables as well as prepayments and other current assets and deferred income taxes. The Company also reclassified all previously recorded goodwill not included in rates to goodwill on the balance sheet. This adjustment resulted in a \$5.6 million decrease in other assets and a corresponding increase in goodwill.

The Company has restated its financial statements to give effect to the matters discussed above. A summary of the significant effects of the restatement on previously reported financial position and results of operations is included in Note 3 to the financial statements. The effects of the restatement on 2001 quarterly results and on 2002 previously reported quarterly information, is discussed in Note 17. The financial statements are included under Item 8 Financial Statements and Supplementary Data.

Nonrecurring Items in 2001 and 2000

Merger and Integration Costs

Merger and integration costs incurred for the years ended December 31, 2001 and 2000 were \$0.6 million (\$0.4 million after tax) and \$14.1 million (\$11.0 million after tax), respectively. Merger and integration activities resulting from the 2000 merger were completed in 2001.

Since March 31, 2000, \$14.7 million has been expensed associated with merger and integration activities. Accruals were established at March 31, 2000 totaling \$7.4 million. Of this amount, \$0.7 million related to employee and executive severance costs and \$6.7 million related to transaction costs and regulatory filing fees incurred prior to the closing of the merger. At December 31, 2001, no accrual remains. The remaining \$7.3 million was expensed (\$6.7 million in 2000 and \$0.6 million in 2001) for accounting fees resulting from merger related filing requirements, consulting fees related to integration activities such as organization structure, employee travel between company locations, internal labor of employees assigned to integration teams, investor relations communication activities, and certain benefit costs.

The integration activities experienced by the Company included such things as information system consolidation, process review and definition, organization design and consolidation, and knowledge sharing.

Restructuring Costs

As part of continued cost saving efforts, in June 2001, Vectren's management and board of directors approved a plan to restructure, primarily, its regulated operations. The restructuring plan included the elimination of certain administrative and supervisory positions in its utility operations and corporate office. Charges of \$4.3 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of \$1.5 million were incurred during the remainder of 2001 primarily related to consulting fees and employee relocation costs. In total, the Company has incurred restructuring charges of \$5.8 million, (\$3.6 million after tax). These charges were comprised of \$4.4 million for employee severance, related benefits and other employee related costs and \$1.4 million for consulting and other fees incurred through December 31, 2001. The restructuring program was completed during 2001, except for the departure of certain employees impacted by the restructuring which occurred during 2002. (See Note 15 for further information on restructuring costs.)

Cumulative Effect of Change in Accounting Principle

Resulting from the adoption of SFAS 133, certain contracts in the power marketing operations that are periodically settled net were required to be recorded at market value. Previously, the Company accounted for these contracts on settlement. The cumulative impact of the adoption of SFAS 133 resulting from marking these contracts to market on January 1, 2001 was an earnings gain of approximately \$1.8 million (\$1.1 million after tax) recorded as a cumulative effect of change in accounting principle in the Statements of Income.

Loss on extinguishment of preferred stock

In September 2001, the Company notified holders of its 4.80%, 4.75%, and 6.50% preferred stock of its intention to redeem the shares. The 4.80% preferred stock was redeemed at \$110.00 per share, plus \$1.35 per share in accrued and unpaid dividends. Prior to the redemption, there were 85,519 shares outstanding.

The 4.75% preferred stock was redeemed at \$101.00 per share, plus \$0.97 per share in accrued and unpaid dividends. Prior to the redemption, there were 3,000 shares outstanding. The 6.50% preferred stock was redeemed at \$104.23 per share, plus \$0.73 per share in accrued and unpaid dividends. Prior to the redemption, there were 75,000 shares outstanding. The total redemption price was \$17.7 million and the loss on redemption totaled \$1.2 million.

Significant Fluctuations

Utility Margin

Electric Utility Margin

Electric Utility margin by customer type and non-firm wholesale margin separated between realized margin and mark-to-market gains and losses follows:

	Year ended December 31,		
In millions	2002	2001	2000
Retail & firm wholesale	\$ 215.3	\$ 200.0	\$ 201.2
Non-firm wholesale	14.9	19.9	21.1
Total margin	\$ 230.2	\$ 219.9	\$ 222.3
Non-firm wholesale margin:			
Realized margin	\$ 18.5	\$ 18.4	\$ 21.1
Mark-to-market gains (losses)	(3.6)	1.5	-

Electric Utility margin for the year ended December 31, 2002 increased \$10.3 million, or 5%, when compared to 2001. The increases result primarily from the effect on retail sales of cooling weather considerably warmer than the prior year. Weather in 2002 was 27% warmer when compared to 2001 and 23% warmer than normal. In addition to weather, 2002 was positively affected by a cash return on NOx compliance expenditures as the expenditures are made pursuant to a rate recovery rider approved by the IURC in August 2001. As a result of warmer weather, retail and firm wholesale volumes sold increased from 5.8 GWh in 2001 to 6.2 GWh in 2002. Volumes sold in 2000 were 5.9 GWh. The current year increase in margin from retail sales was partially offset by lower margins earned in the wholesale energy market.

Electric Utility margin for the year ended December 31, 2001 decreased \$2.4 million, or 1%, compared to 2000 primarily from decreased sales to firm wholesale customers and decreased margin on non-firm wholesale activity. The decreases were partially offset by a 3% increase in residential and commercial sales due to cooling weather 7% warmer than the prior year and a 3% increase in the number of residential and commercial customers.

Periodically, generation capacity is in excess of that needed to serve retail and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. The contracts entered into are primarily short-term purchase and sale transactions that expose the Company to limited market risk. While volumes both sold and purchased in the wholesale market have increased during 2002, margins softened as a result of reduced price volatility. As a result of increased activity offset by reduced price volatility, margin from power marketing activities decreased \$5.0 million during 2002 and \$1.2 million during 2001. In 2002, volumes sold into the wholesale market were 10.7 GWh compared to 3.4 GWh in 2001 and 1.6 GWh in 2000. Volumes purchased from the wholesale market, some of which were utilized to serve retail and firm wholesale customers, were 10.3 GWh in 2002 compared to 2.9 GWh in 2001 and 1.2 GWh in 2000.

Gas Utility Margin

Gas Utility margin for the year ended December 31, 2002 of \$32.4 million increased \$6.5 million. The increase is primarily due to weather 4% cooler for the year and 26% cooler in the fourth quarter and

customer growth of almost 1%. The Company's total throughput was 32.0 MMDth in 2002, 31.9 MMDth in 2001, and 35.6 MMDth in 2000. The change in throughput between 2002 and 2001 reflects a 10% increase in retail and commercial volumes sold offset by a decrease in contract volumes that primarily represent transported volumes.

Gas Utility margin for the year ended December 31, 2001 of \$25.9 million decreased \$4.4 million, compared to 2000. The primary factors contributing to this decrease were weather that was 10% warmer than the prior year and the unfavorable impact resulting from extraordinarily high gas costs early in 2001, coupled with the effects of a weakened economy.

Cost of gas sold was \$53.1 million in 2002, \$72.7 million in 2001, and \$78.9 million in 2000. Cost of gas sold decreased \$19.6 million, or 27%, during 2002 compared to 2001, primarily due to a return to lower gas prices somewhat offset by an increase in retail volumes sold. Cost of gas sold decreased \$6.2 million, or 8%, in 2001. The decrease is primarily due to lower volumes sold due to the warmer weather, a weakened economy, and lower gas prices. The total average cost per dekatherm of gas purchased was \$4.20 in 2002, \$5.20 in 2001, and \$5.46 in 2000. The price changes are due primarily to changing commodity costs in the marketplace.

Operating Expenses

Other Operating

Other operating expenses decreased \$4.1 million for the year ended December 31, 2002 when compared to 2001. The decrease results primarily from insurance recovery in 2002 of certain maintenance costs incurred in 2001, a return to lower gas prices, and the related reduction in costs incurred in 2001. Specific expenses affected by increased gas costs in 2001 were uncollectible accounts expense and contributions to low income heating assistance programs.

Depreciation and Amortization

Depreciation and amortization increased \$1.8 million for the year ended December 31, 2002 when compared to 2001. The increase results primarily from the depreciation of additions to plant assets including an 80 MW gas turbine placed into service in June 2002. Depreciation and amortization for 2001 was comparable to 2000.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased \$1.3 million in 2002 compared to 2001 as a result of lower revenues subject to gross receipts tax and were basically unchanged in 2001 compared to 2000.

Interest Expense

Interest expense increased \$2.2 million in 2002 compared to 2001. The increase is attributable to higher outstanding borrowings during 2002 due to the funding of NOx expenditures with short-term borrowing.

Interest expense increased \$1.0 million during the 2001 compared to 2000. The increase is due primarily to increased working capital requirements resulting from higher natural gas prices.

Income Tax

Federal and state income taxes increased \$9.0 million in 2002 compared to 2001 and decreased \$2.8 million in 2001 compared to 2000. The changes in income taxes result principally from fluctuations in pre-tax earnings. The effective tax rate in 2000 was higher due to the nondeductibility of certain merger and integration costs.

Critical Accounting Policies

Management is required to make judgements, assumptions, and estimates that affect the amounts reported in the financial statements and the related disclosures that conform to accounting principles generally accepted in the United States. Note 2 to the financial statements describes the significant accounting policies and methods used in the preparation of the financial statements. Certain estimates used in the financial statements are subjective and use variables that require judgement. These include the estimates to perform goodwill asset impairment 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 plant, the valuation of derivative contracts and the allowance for doubtful accounts, among others. Actual results could differ from these estimates.

Goodwill

Pursuant to SFAS No. 142, the Company performed an initial impairment analysis of its goodwill, all of which resides in the Gas Utility Services operating segment. Also consistent with SFAS 142, goodwill is tested for impairment annually at the beginning of the year and more frequently if events or circumstances indicate that an impairment loss has been incurred. Impairment tests are performed at the reporting unit level which the Company has determined to be consistent with its Gas Utility Services operating segment as identified in Note 14 to the financial statements. 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 and therefore resulted in no impairment.

Estimating fair value using a discounted cash flow model is subjective and requires significant judgement 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 results 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. 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, these estimates are 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 judgement 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 and certain subsidiaries of Vectren provided corporate and general and administrative services to the Company including legal, finance, tax, risk management, and human resources, which includes charges for restricted stock compensation and for pension and other postretirement benefits not directly charged to subsidiaries. These costs have been allocated using various allocators, primarily number of employees, number of customers and/or revenues. 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. In addition, Vectren negotiates service and construction contracts on behalf of its utilities to obtain those services at less cost than the utility may otherwise be able to obtain on its own. The allocation methodology is not subject to near term changes.

Pension and Other Postretirement Obligations

Vectren satisfies the future funding requirements of its pension and other postretirement plans and the payment of benefits from general corporate assets. 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 from prior service and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. Plan assets nor the FAS 87/106 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. 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 annually measures its obligations on September 30.

Vectren estimates the expected return on plan assets, discount rate, rate of compensation increase, and future health care costs, among other things, and relies on actuarial estimates to assess the future potential liability and funding requirements of pension and postretirement plans. Vectren used the following weighted average assumptions to develop 2002 annual costs and the ending benefit obligations recognized in its consolidated financial statements: a discount rate of 6.75%, an expected return on plan assets before expenses of 9.00%, a rate of compensation increase of 4.25%, and a health care cost trend rate of 10% in 2002 declining to 5% in 2006. During 2002, Vectren reduced the discount rate and rate of compensation increase by 50 basis points from those assumptions used in 2001 due to the general decline in interest rates and other market conditions that occurred in 2002. Future changes in health care costs, work force demographics, interest rates, or plan changes could significantly affect the estimated cost of these future benefits that are allocated to the Company.

Impact of Recently Issued Accounting Guidance

EITF 02-03

In October 2002, the EITF reached a final consensus in EITF Issue 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) that gains and losses (realized and unrealized) on all derivative instruments within the scope of SFAS 133 should be shown net in the income statement, whether or not settled physically, if the derivative instruments are held for "trading purposes." The consensus rescinded EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10) as well as other decisions reached on energy trading contracts at the EITF's June 2002 meeting.

The Company's non-firm wholesale power marketing operations enter into contracts that are derivatives as defined by SFAS 133, but these operations do not meet the definition of energy trading activities based upon the provisions in EITF 98-10. Currently, the Company uses a gross presentation to report the results of these operations as described in Note 12 of the financial statements. The Company has re-evaluated its portfolio of derivative contracts and has determined gross presentation remains appropriate.

SFAS 143

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation 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 to its present value, 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 upon settlement. Any costs of removal recorded in accumulated depreciation pursuant to regulatory authority will require disclosure in future periods. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations or financial condition.

FASB Interpretation (FIN) 45

In November 2002, the FASB issued Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the requirements for a guarantor's accounting for and disclosure of certain guarantees issued and outstanding and that a guarantor is required to recognize, at the inception of a guarantee, a liability for the obligations it has undertaken. The objective of the initial measurement of that liability is the fair value of the guarantee at its inception. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Although management is still evaluating the impact of FIN 45 on its financial position and results of operations, the adoption is not expected to have a material effect.

FIN 46

In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 addresses consolidation by business enterprises of variable interest entities and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies to variable interest entities and, thus improves comparability between enterprises engaged in similar activities when those activities are conducted through variable interest entities. FIN 46 applies to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. FIN 46 applies to the Company's third quarter for variable interest entities in which the Company holds a variable interest acquired before February 1, 2003. Although management is still evaluating the impact of FIN 46 on its financial position and results of operations, the adoption is not expected to have a material effect.

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, including, but not limited to Vectren's realization of net merger savings, 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 or regulatory 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 natural gas transmission, gathering and processing, and similar entities with regulatory oversight.
- Economic conditions including the effects of an economic downturn, inflation rates, and monetary fluctuations.
- 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.
- Availability or cost of capital, resulting from changes in the Company, including its security ratings, changes in interest rates, and/or changes in market perceptions of the utility industry and other energy-related industries.
- Employee workforce factors including changes in key executives, collective bargaining agreements with union employees, 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.
- Changes in federal, state or local legislature 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.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to various business risks associated with commodity prices, interest rates, and counter-party credit. These financial exposures are monitored and managed by the Company as an integral part of its overall risk management program. The Company's risk management program includes, among other things, the use of derivatives to mitigate risk.

The Company also executes derivative contracts in the normal course of operations while buying and selling commodities and other fungible goods to be used in operations and while optimizing generation assets. The Company does not execute derivative contracts for speculative or trading purposes.

Commodity Price Risk

The Company's operations have limited exposure to commodity price risk for purchases and sales of natural gas and electricity for retail customers due to current Indiana regulations, which subject to compliance with those regulations, allow for recovery of such purchases through natural gas and fuel cost adjustment mechanisms.

Electric sales and purchases in the wholesale power market and other commodity-related operations are exposed to commodity price risk associated with fluctuating electric power and other commodity prices. Other commodity operations include sales of electricity to certain municipalities and large industrial customers.

The Company's non-firm wholesale power marketing operations manage the utilization of its available electric generating capacity by entering into forward and option 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's other commodity-related operations involve the purchase and sale of commodities, including electricity, to meet customer demands and operational needs. These operations also enter into forward contracts that commit the Company to purchase and sell commodities in the future. Price risk from forward positions that commit the Company to deliver commodities is mitigated using insurance contracts and offsetting forward purchase contracts.

Open positions in terms of price, volume, and specified delivery points may occur and are managed using methods described above and frequent management reporting.

Market risk is measured by management as the potential impact on pre-tax earnings resulting from a 10% adverse change in the forward price of commodity prices on outstanding market sensitive financial instruments (all contracts not expected to be settled by physical receipt or delivery). For the years ended December 31, 2002 and 2001, a 10% adverse change in commodity forward prices on market sensitive financial instruments would have decreased pre-tax earnings by approximately \$1.5 million and \$2.0 million, respectively.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its adjustable rate borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on operations. The Company tries to limit the amount of adjustable rate borrowing arrangements exposed to short-term interest rate volatility to a maximum of 25% of total debt. However, there are times when this targeted level of interest rate exposure may be exceeded. At December 31, 2002, such obligations represented 10% of the Company's total debt portfolio. To manage this exposure, the Company may periodically use derivative financial instruments to reduce earnings fluctuations caused by interest rate volatility.

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 including bank notes, lines of credit, commercial paper, and certain adjustable rate long-term debt instruments. At December 31, 2002 and 2001, the combined borrowings under these facilities totaled \$61.9 million and \$104.0 million, respectively. Based upon average borrowing rates under these facilities during the years ended December 31, 2002 and 2001, an increase of 100 basis points (1%) in the rates would have increased interest expense by \$0.9 million and \$0.7 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. 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.

Although the Company's 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The management of Southern Indiana Gas and Electric Company (SIGECO) is responsible for the preparation of the financial statements and the related financial data contained in this report. The financial statements are 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 the data in this report, including required estimates and judgments, is the responsibility of management. Management maintains a system of internal control and utilizes an internal auditing program to provide reasonable assurance of compliance with Company policies and procedures and the safeguard of assets.

The board of directors of Vectren Corporation (Vectren), the parent company of SIGECO, pursues its responsibility for these financial statements through its audit committee, which meets periodically with management, the internal auditors and the independent auditors, to assure that each is carrying out its responsibilities. Both the internal auditors and the independent auditors meet with the audit committee of Vectren's board of directors, with and without management representatives present, to discuss the scope and results of their audits, their comments on the adequacy of internal accounting control and the quality of financial reporting.

/S/ Niel C. Ellerbrook
Niel C. Ellerbrook
Chairman & Chief Executive Officer
February 26, 2003

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors of Southern Indiana Gas and Electric Company:

We have audited the accompanying balance sheets of Southern Indiana Gas and Electric Company as of December 31, 2002 and 2001, and the related statements of income, common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2002. Our audits also included the financial statement schedule listed in the Table of Contents 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 financial statements present fairly, in all material respects, the financial position of Southern Indiana Gas and Electric Company as of December 31, 2002 and 2001, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2002, 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 financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 12, effective, January 1, 2001, the Company adopted SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

As discussed in Note 3, the accompanying 2001 and 2000 financial statements have been restated.

/S/ DELOITTE & TOUCHE LLP
DELOITTE & TOUCHE LLP
Indianapolis, Indiana
February 26, 2003

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(In thousands)

	December 31, 2002	December 31, 2001 (As Restated, See Note 3)
ASSETS		
Utility Plant		
Original cost	\$ 1,526,094	\$ 1,456,805
Less: Accumulated depreciation & amortization	728,768	690,344
Net utility plant	797,326	766,461
Current Assets		
Cash & cash equivalents	2,145	1,556
Accounts receivable-less reserves of \$3,662 & \$3,188, respectively	50,454	41,811
Receivables from other Vectren companies	18,015	19,625
Accrued unbilled revenues	33,027	17,013
Inventories	39,653	37,633
Recoverable fuel & natural gas costs	9,615	22,206
Prepayments & other current assets	5,926	6,238
Total current assets	158,835	146,082
Investments in unconsolidated affiliates	150	160
Other investments	10,019	9,242
Non-utility property-net	3,568	4,386
Goodwill-net	5,557	5,557
Regulatory assets	49,859	47,465
Other assets	344	539
TOTAL ASSETS	\$ 1,025,658	\$ 979,892

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(In thousands)

	December 31, 2002	December 31, 2001 (As Restated, See Note 3)
LIABILITIES & SHAREHOLDER'S EQUITY		
Capitalization		
Common shareholder's equity		
Common stock (no par value)	\$ 103,258	\$ 78,258
Retained earnings	270,181	255,942
Total common shareholder's equity	373,439	334,200
Cumulative redeemable preferred stock	344	460
Long-term debt-net of current maturities & debt subject to tender	264,238	291,702
Long-term debt due to VUHI	86,574	49,460
Total capitalization	724,595	675,822
Commitments & Contingencies (Notes 4-6)		
Current Liabilities		
Accounts payable	25,215	27,293
Accounts payable to affiliated companies	10,013	-
Payables to other Vectren companies	15,211	9,924
Accrued liabilities	30,713	30,677
Short-term borrowings	-	874
Short-term borrowings due to VUHI	39,419	80,664
Long-term debt subject to tender	26,640	-
Current maturities of long-term debt	1,000	-
Total current liabilities	148,211	149,432
Deferred Income Taxes & Other Liabilities		
Deferred income taxes	112,004	115,523
Deferred credits & other liabilities	40,848	39,115
Total deferred income taxes & other liabilities	152,852	154,638
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	\$ 1,025,658	\$ 979,892

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
STATEMENTS OF INCOME
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
OPERATING REVENUES		(As Restated, See Note 3)	
Electric revenues	\$ 608,116	\$ 381,233	\$ 334,428
Gas revenues	85,461	98,580	109,142
Total operating revenues	693,577	479,813	443,570
COST OF OPERATING REVENUES			
Fuel for electric generation	81,619	74,401	75,699
Purchased electric energy	296,267	86,928	36,394
Cost of gas sold	53,100	72,713	78,903
Total cost of operating revenues	430,986	234,042	190,996
TOTAL OPERATING MARGIN	262,591	245,771	252,574
OPERATING EXPENSES			
Other operating	97,362	104,535	102,002
Merger & integration costs	-	588	14,072
Restructuring costs	-	5,825	-
Depreciation & amortization	45,098	43,287	43,214
Income taxes	30,637	21,648	24,425
Taxes other than income taxes	11,760	13,090	13,259
Total operating expenses	184,857	188,973	196,972
OPERATING INCOME	77,734	56,798	55,602
Other income – net	4,794	5,629	4,674
Interest expense	23,168	20,924	19,893
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	59,360	41,503	40,383
Cumulative effect of change in accounting principle-net of tax	-	1,107	-
NET INCOME	59,360	42,610	40,383
Preferred stock dividends	33	758	1,017
Loss on extinguishment of preferred stock	-	1,170	-
NET INCOME APPLICABLE TO COMMON SHAREHOLDER	\$ 59,327	\$ 40,682	\$ 39,366

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES		(As Restated, See Note 3)	
Net income	\$ 59,360	\$ 42,610	\$ 40,383
Adjustments to reconcile net income to cash from operating activities:			
Depreciation & amortization	45,098	43,287	43,214
Deferred income taxes & investment tax credits	(6,461)	467	(8,613)
Net unrealized gain on derivative instruments, including cumulative effect of change in accounting principle	3,585	8,935	-
Other non-cash charges- net	3,167	864	2,579
Changes in working capital accounts:			
Accounts receivable, including to Vectren companies & accrued unbilled revenue	(24,950)	19,633	(38,752)
Inventories	(2,020)	(6,578)	10,404
Recoverable fuel & natural gas costs	12,591	6,497	(23,118)
Prepayments & other current assets	(5,419)	(12,054)	4,994
Accounts payable, including to Vectren companies & affiliated companies	34,332	(40,682)	43,011
Accrued liabilities	(345)	(18,784)	8,571
Other noncurrent assets & liabilities	(3,134)	7	(16,352)
Net cash flows from operating activities	115,804	44,202	66,321
CASH FLOWS (REQUIRED FOR) FROM FINANCING ACTIVITIES			
Proceeds from:			
Long-term debt due to VUHI	37,114	49,460	-
Additional capital contribution	25,000	-	-
Requirements for:			
Dividends on common stock	(45,088)	(38,909)	(28,639)
Redemption of preferred stock	(116)	(17,676)	(2,000)
Dividends on preferred stock	(33)	(758)	(1,017)
Net change in short-term borrowings, including due to VUHI	(42,119)	41,384	17,274
Proceeds from other financing activities	-	-	1,974
Net cash flows (required for) from financing activities	(25,242)	33,501	(12,408)
CASH FLOWS (REQUIRED FOR) INVESTING ACTIVITIES			
Proceeds from sale of investments and assets	1,400	-	-
Requirements for:			
Capital expenditures	(89,747)	(77,760)	(51,119)
Other investments	(1,626)	-	(1,630)
Net cash flows (required for) investing activities	(89,973)	(77,760)	(52,749)
Net increase (decrease) in cash & cash equivalents	589	(57)	1,164
Cash & cash equivalents at beginning of period	1,556	1,613	449
Cash & cash equivalents at end of period	\$ 2,145	\$ 1,556	\$ 1,613

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
STATEMENTS OF COMMON SHAREHOLDER'S EQUITY
(In thousands)

	Common Stock	Retained Earnings	Total
Balance at January 1, 2000, As Reported	\$ 78,258	\$ 256,312	\$ 334,570
Restatement adjustment	-	2,923	2,923
Balance at January 1, 2000, As Restated	78,258	259,235	337,493
Net income & comprehensive income, As Restated		40,383	40,383
Common stock dividends		(28,639)	(28,639)
Preferred stock dividends		(1,017)	(1,017)
Distribution of assets to parent		(9,144)	(9,144)
Other		317	317
Balance at December 31, 2000, As Restated	78,258	261,135	339,393
Net income & comprehensive income, As Restated		42,610	42,610
Common stock dividends		(38,909)	(38,909)
Preferred stock dividends		(758)	(758)
Distribution of assets to parent		(6,966)	(6,966)
Loss on redemption of preferred stock		(1,170)	(1,170)
Balance at December 31, 2001, As Restated	78,258	255,942	334,200
Net income & comprehensive income		59,360	59,360
Common stock:			
Additional capital contribution	25,000		25,000
Dividends		(45,088)	(45,088)
Preferred stock dividends		(33)	(33)
Balance at December 31, 2002	\$ 103,258	\$ 270,181	\$ 373,439

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

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
NOTES TO THE FINANCIAL STATEMENTS

1. Organization and Nature of Operations

Overview

Southern Indiana Gas and Electric Company (the Company or SIGECO), an Indiana corporation, provides electric generation, transmission, and distribution services to 8 counties in southwestern Indiana, including counties surrounding Evansville, and participates in the wholesale power market. The Company also provides natural gas distribution and transportation services to 10 counties in southwestern Indiana, including counties surrounding Evansville. SIGECO is a direct subsidiary of Vectren Utility Holdings, Inc. (VUHI). VUHI is a direct, wholly owned subsidiary of Vectren Corporation (Vectren).

Vectren was organized on June 10, 1999 solely for the purpose of effecting the merger of Indiana Energy, Inc. (Indiana Energy) and SIGCORP, Inc. (SIGCORP). On March 31, 2000, the merger of Indiana Energy with SIGCORP and into Vectren was consummated with a tax-free exchange of shares and has been accounted for as a pooling-of-interests in accordance with APB Opinion No. 16 "Business Combinations."

Vectren's wholly owned subsidiary, VUHI, serves as the intermediate holding company for its three operating public utilities: Indiana Gas Company, Inc. (Indiana Gas), formerly a wholly owned subsidiary of Indiana Energy, SIGECO, formerly a wholly owned subsidiary of SIGCORP, and the Ohio operations, a utility jointly owned by Indiana Gas and Vectren Energy Delivery of Ohio, Inc. (VEDO). Both Vectren and VUHI are exempt from registration pursuant to Section 3(a)(1) and 3(c) of the Public Utility Holding Company Act of 1935.

2. Summary of Significant Accounting Policies

A. Cash and Cash Equivalents

All highly liquid investments with an original maturity of three months or less at the date of purchase are considered cash equivalents. Cash paid during the periods reported for interest and income taxes follows:

	Year Ended December 31,		
In thousands	2002	2001	2000
Cash paid during the year for			
Interest (net of amount capitalized)	\$ 20,598	\$18,992	\$17,506
Income taxes	41,441	47,960	21,627

B. Inventories

Inventories consist of the following:

	At December 31,	
In thousands	2002	2001
Materials & supplies	\$ 15,836	\$16,304
Gas in storage – at LIFO cost	12,880	10,542
Fuel (coal and oil) for electric generation	10,030	9,513
Emission allowances	907	1,274
Total inventories	\$ 39,653	\$37,633

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, 2002 and 2001 by approximately \$19.0 million and \$15.8 million, respectively. All other inventories are carried at average cost.

C. Utility Plant and Depreciation

Utility plant is stated at historical cost, including AFUDC. Depreciation of utility plant is provided using the straight-line method over the estimated service lives of the depreciable assets. The original cost of utility plant, together with depreciation rates expressed as a percentage of original cost, follows:

In thousands	At & For the Year Ended December 31,			
	2002		2001	
	Depreciation		Depreciation	
	Rates as a Percent of Original Cost		Rates as a Percent of Original Cost	
Electric utility plant	\$ 1,211,036	2.9%	\$ 1,148,887	3.3%
Gas utility plant	164,510	3.3%	155,051	3.0%
Common utility plant	41,621	2.6%	41,197	2.6%
Construction work in progress	108,927	-	111,670	-
Total original cost	\$ 1,526,094		\$ 1,456,805	

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 and is included in other – net in the 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:

In thousands	Year Ended December 31,		
	2002	2001	2000
AFUDC – equity funds	\$ 1,746	\$ 1,653	\$ 2,051
AFUDC – borrowed funds	1,933	1,371	1,817
Total AFUDC capitalized	\$ 3,679	\$ 3,024	\$ 3,868

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 cost of such property is credited to utility plant, and such cost, together with the cost of removal less salvage, is charged to accumulated depreciation.

D. 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), which the Company adopted as required on January 1, 2002. 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 replaced authoritative guidance in SFAS No. 121, “Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of” (SFAS 121) and certain aspects of APB Opinion No. 30, “Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business.” SFAS 144 retains the framework of SFAS 121 and requires the evaluation for impairment involve the comparison of an asset’s carrying value to the estimated future cash flows 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.

E. Goodwill

Goodwill arising from past business combinations is accounted for in accordance with SFAS No. 142, “Goodwill and Other Intangible Assets” (SFAS 142). The Company adopted SFAS 142, as required on January 1, 2002.

SFAS 142 changed the accounting for goodwill from an amortization approach to an impairment-only approach. Thus, amortization of goodwill that was not included as an allowable cost for rate-making purposes ceased upon SFAS 142's adoption.

Goodwill is to be tested for impairment at a reporting unit level at least annually. The impairment review consists 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. Prior to the adoption of SFAS 142, the Company amortized goodwill on a straight-line basis over 40 years. SFAS 142 required an initial impairment review of all goodwill within six months of the adoption date. Results of the initial impairment review were to be treated as a change in accounting principle in accordance with APB Opinion No. 20 "Accounting Changes."

As required by SFAS 142, amortization of goodwill ceased on January 1, 2002. Amortization approximated \$0.2 million (\$0.1 million after tax) in both 2001 and 2000. The Company's goodwill is included in the Gas Utility Services operating segment. Initial impairment reviews to be performed within six months of adoption of SFAS 142 were completed and resulted in no impairment. The impairment test is performed at the beginning of each year.

F. Regulation SFAS 71

Retail public utility operations affecting Indiana customers are subject to regulation by the IURC. The Company's accounting policies give recognition to the rate-making and accounting practices of this agency 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). Regulatory assets represent probable future revenues associated with certain incurred costs, which will be recovered from customers through the rate-making process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the rate-making process.

The Company assesses the recoverability of costs recognized as regulatory assets 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 regulatory assets. Regulatory assets consist of the following:

	At December 31,	
In thousands	2002	2001
Demand side management programs	\$ 32,062	\$ 31,667
Regulatory income tax asset	7,334	8,245
Unamortized debt discount & expenses	3,011	3,155
Other	7,452	4,398
Total regulatory assets	\$ 49,859	\$ 47,465

As of December 31, 2002, regulatory assets totaling \$17.3 million are reflected in rates charged to customers, of which \$6.9 million is earning a return. The remaining \$32.6 million, which is not yet included in rates, represents primarily electric demand side management (DSM) costs incurred after 1993. The Company has rate orders for all deferred costs not yet in rates and therefore believes that future recovery is probable. At December 31, 2002, the weighted average recovery period of regulatory assets, other than those arising from book-tax basis differences, included in rates is 8.3 years. Regulatory income tax assets are recovered as deferred tax assets and liabilities discussed in Note 5 become payable or receivable.

Refundable or Recoverable Gas Costs, Fuel for Electric Production and 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 typically contain a fuel adjustment clause that allows for adjustment in charges for electric energy to reflect changes in the cost of fuel and the net energy cost of purchased power. Metered electric rates also allow recovery, through a quarterly rate adjustment mechanism, for the margin on electric sales lost due to the implementation of demand side management programs.

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.

G. 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.

H. Excise and Gross Receipts Taxes

Excise taxes and a portion of gross receipts taxes are included in rates charged to customers. Accordingly, the Company records these taxes received as a component of operating revenues. Excise and gross receipts taxes paid are recorded as a component of taxes other than income taxes.

I. Earnings Per Share

Earnings per share are not presented as the Company's common stock is wholly owned by Vectren Utility Holdings, Inc.

J. 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. Restatement of Previously Reported Results

The Company identified adjustments that, in the aggregate, reduced previously reported 2001 earnings by approximately \$1.8 million after tax, decreased previously reported 2000 results by approximately \$0.7 million after tax, and increased retained earnings as of January 1, 2000 by \$2.9 million after tax. Adjustments were also made to previously reported 2002 quarterly results. In addition to adjustments affecting previously reported net income, other reclassifications were made to the previously reported 2001 and 2000 results to conform with the 2002 presentation.

Previously Reported 2001 and 2000 Net Income Adjustments

The Company determined that \$3.3 million (\$2.0 million after tax) of gas costs were improperly recorded as recoverable gas costs due from customers. The error related primarily to the accounting for natural gas inventory and resulted in an overstatement of 2001 earnings.

The Company also identified an accounting error related to certain employee benefit and other related costs that are routinely accumulated on the balance sheet and systematically cleared to operating expense and capital projects. Because of inadequate loading rates, these costs were not fully cleared to operating expense and capital projects in 2001. As a result, 2001 earnings were overstated by \$1.5 million (\$0.9 million after tax).

The accounting for certain wholesale power marketing contracts was modified to comply with SFAS 133, which became effective on January 1, 2001. The cumulative effect at adoption was decreased by \$2.8 million after tax. This change was offset substantially by an increase in electric margins throughout 2001.

Originally reflected in 2001, the Company also reflected a correction of the year 2000 overstatement of electric revenue totaling \$2.4 million (\$1.5 million after tax), now reflected in 2000 as discussed below.

The Company identified other reconciliation errors and other errors related to the recording of estimates that were not significant, either individually or in the aggregate. As a result of these additional items, 2001 earnings were reduced by \$0.6 million (\$0.4 million after tax).

The Company also determined that certain billings and collections had been improperly recorded in 2000, resulting in an overstatement of electric revenue by \$2.4 million (\$1.5 million after tax). Other errors were identified that increased 2000 earnings by \$1.3 million (\$0.8 million after tax). The impact of the restatement of results for the year ended 2000 is a reduction to pre-tax income and net income of \$1.1 million and \$0.7 million, respectively.

Previously Reported 2002 Quarterly Net Income Adjustments

As previously reported, in the second quarter of 2002 the Company recorded \$5.2 million (\$3.2 million after tax) of carrying costs for DSM programs pursuant to existing IURC orders and based on an improved regulatory environment. During the audit of the three years ended December 31, 2002, management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in 2002 quarterly results were reversed and reflected in common shareholder's equity as of January 1, 2000. In addition, the Company identified other adjustments that were not significant, either individually or in the aggregate that increased previously reported 2002 quarterly pre-tax and after tax earnings by approximately \$0.2 million and \$0.1 million after tax, respectively. The cumulative impact from these adjustments reduced previously reported earnings for the nine months ended September 30, 2002 by approximately \$3.3 million.

Beginning Retained Earnings Adjustments

In addition to the adjustment of DSM costs above, the Company identified other errors that were not significant, either individually or in the aggregate that relate to years prior to 2000 resulting in a cumulative net increase of \$2.9 million in retained earnings as of January 1, 2000.

Other Balance Sheet Adjustments

Certain reclassifications were made to reflect separate Company current and deferred income taxes are included in Vectren's consolidated tax position. These reclassifications are the principal adjustments to intercompany receivables and payables as well as prepayments and other current assets and deferred income taxes. The Company also reclassified all previously recorded goodwill not included in rates to goodwill on the balance sheet. This adjustment resulted in a \$5.6 million decrease in other assets and a corresponding increase in goodwill.

The Company has restated its financial statements to give effect to the matters discussed above. Following is a summary of the significant effects of the restatement on previously reported financial position and results of operations. The effects of the restatement on 2001 quarterly results and on 2002 previously reported quarterly information, is discussed in Note 17. Note 17 is unaudited.

The effects on the income statement for the year ending December 31, 2001 (in thousands) follow:

	As Reported	Adjustments	As Restated
OPERATING REVENUES			
Electric revenues	\$ 378,867	\$ 2,366	\$ 381,233
Gas revenues	101,117	(2,537)	98,580
Total operating revenues	479,984	(171)	479,813
COST OF OPERATING REVENUES			
Fuel for electric generation	74,402	(1)	74,401
Purchased electric energy	91,666	(4,738)	86,928
Cost of gas sold	72,829	(116)	72,713
Total cost of operating revenues	238,897	(4,855)	234,042
TOTAL OPERATING MARGIN	241,087	4,684	245,771
OPERATING EXPENSES			
Other operating	101,868	2,667	104,535
Merger & integration costs	588	-	588
Restructuring costs	5,825	-	5,825
Depreciation & amortization	43,287	-	43,287
Income taxes	20,762	886	21,648
Taxes other than income taxes	13,090	-	13,090
Total operating expenses	185,420	3,553	188,973
OPERATING INCOME	55,667	1,131	56,798
Other income – net	5,778	(149)	5,629
Interest expense	20,993	(69)	20,924
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	40,452	1,051	41,503
Cumulative effect of change in accounting principle-net of tax	3,938	(2,831)	1,107
NET INCOME	44,390	(1,780)	42,610
Preferred stock dividends	758	-	758
Loss on extinguishment of preferred stock	1,170	-	1,170
NET INCOME APPLICABLE TO COMMON SHAREHOLDER	\$ 42,462	\$ (1,780)	\$ 40,682

The effects on the income statement for the year ending December 31, 2000 (in thousands) follow:

	As Reported	Adjustments	As Restated
OPERATING REVENUES			
Electric revenues	\$ 336,409	\$ (1,981)	\$ 334,428
Gas revenues	109,284	(142)	109,142
Total operating revenues	445,693	(2,123)	443,570
COST OF OPERATING REVENUES			
Fuel for electric generation	75,699	-	75,699
Purchased electric energy	36,394	-	36,394
Cost of gas sold	78,903	-	78,903
Total cost of operating revenues	190,996	-	190,996
TOTAL OPERATING MARGIN	254,697	(2,123)	252,574
OPERATING EXPENSES			
Other operating	103,053	(1,051)	102,002
Merger & integration costs	14,072	-	14,072
Depreciation & amortization	43,214	-	43,214
Income taxes	24,832	(407)	24,425
Taxes other than income taxes	13,258	1	13,259
Total operating expenses	198,429	(1,457)	196,972
OPERATING INCOME	56,268	(666)	55,602
Other income – net	4,674	-	4,674
Interest expense	19,894	(1)	19,893
NET INCOME	41,048	(665)	40,383
Preferred stock dividends	1,017	-	1,017
NET INCOME APPLICABLE TO COMMON SHAREHOLDER	\$ 40,031	\$ (665)	\$ 39,366

The effects on the balance sheet as of December 31, 2001 (in thousands) follow:

ASSETS	As Reported	Adjustments	As Restated
Utility Plant			
Original cost	\$ 1,455,826	\$ 979	\$ 1,456,805
Less: Accumulated depreciation & amortization	690,344	-	690,344
Net utility plant	765,482	979	766,461
Current Assets			
Cash & cash equivalents	2,451	(895)	1,556
Accounts receivable-less reserves	41,227	584	41,811
Receivables from other Vectren companies	-	19,625	19,625
Accrued unbilled revenues	17,013	-	17,013
Inventories	38,322	(689)	37,633
Recoverable fuel & natural gas costs	22,132	74	22,206
Prepayments & other current assets	24,118	(17,880)	6,238
Total current assets	145,263	819	146,082
Investments in unconsolidated affiliates	160	-	160
Other investments	9,254	(12)	9,242
Non-utility property-net	4,386	-	4,386
Goodwill-net	-	5,557	5,557
Regulatory assets	41,525	5,940	47,465
Other assets	7,152	(6,613)	539
TOTAL ASSETS	\$ 973,222	\$ 6,670	\$ 979,892
LIABILITIES & SHAREHOLDER'S EQUITY			
Capitalization			
Common shareholder's equity			
Common stock (no par value)	\$ 78,258	\$ -	\$ 78,258
Retained earnings	255,464	478	255,942
Accumulated other comprehensive income	94	(94)	-
Total common shareholder's equity	333,816	384	334,200
Cumulative redeemable preferred stock of subsidiary	460	-	460
Long-term debt-net of current maturities	291,702	-	291,702
Long-term debt due to VUHI	49,460	-	49,460
Total capitalization	675,438	384	675,822
Current Liabilities			
Accounts payable	27,135	158	27,293
Payables to other Vectren companies	3,390	6,534	9,924
Accrued liabilities	33,545	(2,868)	30,677
Short-term borrowings	874	-	874
Short-term borrowings due to VUHI	80,664	-	80,664
Total current liabilities	145,608	3,824	149,432
Deferred Income Taxes & Other Liabilities			
Deferred income taxes	112,746	2,777	115,523
Deferred credits & other liabilities	39,430	(315)	39,115
Total deferred income taxes & other liabilities	152,176	2,462	154,638
TOTAL LIABILITIES & SHAREHOLDER'S EQUITY	\$ 973,222	\$ 6,670	\$ 979,892

4. Transactions With Other Vectren Companies

Support Services and Purchases

Vectren and certain subsidiaries of Vectren provided corporate and general and administrative services to the Company including legal, finance, tax, risk management, and human resources, which includes charges for restricted stock compensation and for pension and other postretirement benefits not directly charged to subsidiaries. These costs have been allocated using various allocators, primarily number of employees, number of customers and/or revenues. Allocations are based on cost. In addition, Vectren negotiates service and construction contracts on behalf of its utilities to obtain those services at less cost than the utility may otherwise be able to obtain on its own. For the year ended December 31, 2002, 2001, and 2000, amounts billed by other wholly owned subsidiaries of Vectren to the Company were \$45.2 million, \$43.5 million, and \$30.2 million, respectively.

Vectren Fuels, Inc., a wholly owned subsidiary of Vectren, owns and operates coal mines from which the Company purchases fuel used for electric generation. Amounts paid for such purchases for the year ended December 31, 2002, 2001, and 2000 were \$62.1 million, \$58.4 million and \$25.7 million, respectively.

Retirement Plans and Other Postretirement Benefits

Vectren has multiple defined benefit pension plans and postretirement plans that require accounting as described in SFAS No. 87 "Employers' Accounting for Pensions and SFAS No. 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions," respectively. Subsequent to the merger forming Vectren, 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 from prior service and asset returns) are charged to individual subsidiaries through the corporate allocation process discussed above. Plan assets nor the FAS 87/106 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, 2002 and 2001 pension expense totaling \$2.6 million and \$2.3 million, respectively, was directly charged by Vectren to the Company. For the years ended December 31, 2002 and 2001 other benefit expenses totaling \$0.6 million and \$0.5 million, respectively, were directly charged by Vectren to the Company. In 2000, the Company recognized \$3.5 million in charges for participation in Vectren benefit plans. As of December 31, 2002 and 2001, \$24.1 million and \$23.0 million is included in other non-current liabilities and represents expense directly charged to the Company that is yet to be funded to Vectren.

Cash Management and Borrowing Arrangements

The Company participates in a centralized cash management program with Vectren, other wholly owned subsidiaries, and banks which permits funding of checks as they are presented.

See Note 7 regarding long and short-term intercompany borrowing arrangements.

Guarantees of Parent Company Debt

Vectren's three operating utility companies, SIGECO, VEDO, and Indiana Gas are guarantors of VUHI's \$350.0 million commercial paper program, of which approximately \$239.1 million is outstanding at December 31, 2002 and VUHI's \$350.0 million unsecured senior notes outstanding at December 31, 2002. VUHI has no independent assets or operations, the guarantees are full and unconditional and joint and several, and VUHI has no subsidiaries other than the subsidiary guarantors.

Stock Based Incentive Plans

The Company does not have stock-based compensation plans separate from Vectren. An insignificant number of the Company's employees participate in Vectren's stock-based compensation plans.

Contribution of Assets

The Company contributed computer software and hardware with a book value of approximately \$6.2 million and \$9.1 million to a wholly owned subsidiary of Vectren (Vectren Resources, LLC) as a special dividend in 2001 and 2000, respectively. Additionally in 2001, the Company contributed certain assets totaling \$0.8 million to VUHI. These contributions of assets are reflected as a reduction of common shareholder's equity and resulted in no gain or loss and are omitted from the Statement of Cash Flows.

5. Income Taxes

Vectren and subsidiary companies file a consolidated federal income tax return. For financial reporting purposes, SIGECO's current and deferred tax expense is computed on a separate company basis. The components of income tax expense and utilization of investment tax credits follows:

In thousands	Year Ended December 31,		
	2002	2001	2000
Current:			
Federal	\$ 30,300	\$ 18,403	\$ 29,788
State	5,766	2,999	3,274
Total current taxes	36,066	21,402	33,062
Deferred:			
Federal	(1,199)	1,640	(7,008)
State	(3,916)	180	(177)
Total deferred taxes	(5,115)	1,820	(7,185)
Amortization of investment tax credits	(1,346)	(1,353)	(1,428)
Total income tax expense	29,605	21,869	24,449
Less: Income tax expense included in other-net	(1,032)	221	24
Income tax expense in operating income	\$ 30,637	\$ 21,648	\$ 24,425

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

	Year Ended December 31,		
	2002	2001	2000
Statutory rate	35.0 %	35.0 %	35.0 %
State & local taxes, net of federal benefit	2.2	2.9	3.5
Nondeductible merger costs	-	-	3.6
Amortization of investment tax credit	(1.5)	(2.2)	(2.2)
All other-net	(2.4)	(0.8)	(1.6)
Effective tax rate	33.3 %	34.9 %	38.3 %

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 follows:

In thousands	At December 31,	
	2002	2001
Noncurrent deferred tax liabilities (assets):		
Depreciation & cost recovery timing differences	\$ 119,739	\$ 117,549
Regulatory assets recoverable through future rates	23,352	24,647
Regulatory liabilities to be settled through future rates	(16,018)	(16,403)
Employee benefit obligations	(13,585)	(9,215)
Other – net	(1,484)	(1,055)
Net noncurrent deferred tax liability	112,004	115,523
Current deferred tax liabilities:		
Deferred fuel costs, net	4,680	7,207
Net current deferred tax liability	4,680	7,207
Net deferred tax liability	\$ 116,684	\$ 122,730

At December 31, 2002 and 2001, investment tax credits totaling \$13.2 million and \$14.6 million, respectively, are included in deferred credits and other liabilities. These investment tax credits are amortized over the lives of the related investments.

6. Transactions with Vectren Affiliates

ProLiance Energy, LLC (ProLiance), a nonregulated energy marketing affiliate of Vectren and Citizens Gas and Coke Utility (Citizens Gas), provides natural gas and related services to Indiana Gas, the Ohio operations, Citizens Gas and others. ProLiance also began providing service to SIGECO and Vectren Retail, LLC (Vectren's retail gas marketer) in 2002. ProLiance's primary business is optimizing the gas portfolios of utilities and providing services to large end use customers. Vectren continues to account for its investment in ProLiance using the equity method of accounting. Purchases from ProLiance for resale and for injections into storage for the years ended December 31, 2002 totaled \$25.6 million. Amounts charged by ProLiance for gas supply services are established by supply agreements. Amounts owed to ProLiance approximated \$10.0 million at December 31, 2002 and are included in accounts payable to affiliated companies in the Balance Sheets. Prior to 2002, the Company paid suppliers directly for its natural gas purchases.

7. Borrowing Arrangements

Long-Term Debt

Senior unsecured obligations and first mortgage bonds outstanding and classified as long-term are as follows.

		At December 31,	
In thousands		2002	2001
Fixed Rate Senior Unsecured Note Payable to VUHI:			
2011, 6.625%	\$	86,574	\$ 49,460
Total long-term debt to VUHI	\$	86,574	\$ 49,460
First Mortgage Bonds to Third Parties:			
Fixed-Rate:			
2003, 1978 Series B, 6.25%, tax exempt	\$	1,000	\$ 1,000
2016, 1986 Series, 8.875%		13,000	13,000
2023, 1993 Series, 7.60%		45,000	45,000
2023, 1993 Series B, 6.00%		22,800	22,800
2025, 1993 Series, 7.625%		20,000	20,000
2029, 1999 Senior Notes, 6.72%		80,000	80,000
Adjustable Rate:			
2015, 1985 Pollution Control Series A, presently 4.30%, tax exempt, next rate adjustment: 2004.		9,975	9,975
2025, 1998 Pollution Control Series A, presently 4.75%, tax exempt, next rate adjustment: 2006.		31,500	31,500
2024, 2000 Environmental Improvement Series A, presently 2.05%, tax exempt, adjusts every 35 days, weighted average for year: 3.13%.		22,500	22,500
Total First Mortgage Bonds		245,775	245,775
Adjustable Rate Senior Unsecured Bonds to Third Parties:			
2020, 1998 Pollution Control Series B, presently 4.40%, tax exempt, next rate adjustment: 2003.		4,640	4,640
2030, 1998 Pollution Control Series B, presently 4.40%, tax exempt, next rate adjustment: 2003.		22,000	22,000
2030, 1998 Pollution Control Series C, presently 5.00%, tax exempt, next rate adjustment: 2006.		22,200	22,200
Total Adjustable Rate Senior Unsecured Bonds		48,840	48,840
Total long-term debt outstanding		294,615	294,615
Less: Debt subject to tender		26,640	-
Current maturities of long-term debt		1,000	-
Unamortized debt premium & discount, net		2,737	2,913
Total long-term debt-net	\$	264,238	\$ 291,702

Issuance Payable to VUHI

In 2001, the Company issued a note payable to VUHI for \$49.5 million, and in 2002 issued a note payable to VUHI for \$37.1 million. These two notes comprise the \$86.6 million of long-term debt due to VUHI at December 31, 2002.

The terms of these notes are identical to the terms of notes issued by VUHI in December 2001 through a public offering (December Notes). The December Notes have an aggregate principal amount of \$250.0 million and an interest rate of 6.625%, priced at 99.302% to yield 6.69% to maturity. The December Notes have no sinking fund requirements, and interest payments are due semi-annually. The December Notes are due December 2011, but may be called by VUHI, 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 of the notes to be redeemed 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 VUHI's indenture, plus 25 basis points.

Long-Term Debt Put and Call Provisions

Certain long-term debt issues contain put and call provisions that can be exercised on various dates before maturity. 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 2002 (in millions) is \$26.6 in 2003, \$10.0 in 2004, zero in 2005, \$53.7 in 2006, zero in 2007, and \$80.0 thereafter.

Long-Term Debt Sinking Fund Requirements and Maturities

The annual sinking fund requirement of the Company'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. The Company intends to meet the 2002 sinking fund requirement by this means and, accordingly, the sinking fund requirement for 2002 is excluded from current liabilities in the Balance Sheets. At December 31, 2002, \$342.8 million of the Company's utility plant remained unfunded under the Company's Mortgage Indenture.

Maturities and sinking fund requirements on long-term debt subject to mandatory redemption during the five years following 2002 are \$1.0 million in 2003, zero in 2004, zero in 2005, zero in 2006, and zero in 2007.

Short-Term Borrowings

SIGECO mainly relies on the short-term borrowing arrangements of VUHI for its short-term working capital needs. Borrowings outstanding at December 31, 2002 were \$39.4 million. The intercompany credit line totals \$150.0 million, but is limited to VUHI's available capacity (\$85.9 million of additional capacity at December 31, 2002) and is subject to the same terms and conditions as VUHI's commercial paper program. At December 31, 2002, the Company has approximately \$5 million of short-term borrowing capacity with third parties to supplement its intercompany borrowing arrangements, of which all is available.

	Year ended December 31,		
	2002	2001	2000
Weighted average total outstanding during the year payable to VUHI (in thousands)	\$ 68,034	\$ 34,791	-
Weighted average total outstanding during the year payable to third parties (in thousands)	\$ 1,875	\$ 12,930	\$ 20,026
Weighted average interest rates during the year:			
VUHI	2.03%	5.24%	N/A
Bank loans	2.56%	5.77%	6.24%

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, 2002, the Company was in compliance with all financial covenants.

8. Cumulative Preferred Stock

Redemption of Preferred Stock

Nonredeemable preferred stock contains call options that were exercised during September 2001 for a total redemption price of \$9.8 million. The 4.80%, \$100 par value preferred stock was redeemed at its stated call price of \$110 per share, plus accrued and unpaid dividends totaling \$1.35 per share. The 4.75%, \$100 par value preferred stock was redeemed at its stated call price of \$101 per share, plus accrued and unpaid dividends totaling \$0.97 per share. Prior to the redemptions and as of December 31, 2000, there were 85,519 shares of the 4.80% Series outstanding and 3,000 shares of the 4.75% Series outstanding.

In September 2001, the 6.50%, \$100 par value preferred stock was redeemed for a total redemption price of \$7.9 million at \$104.23 per share, plus \$0.73 per share in accrued and unpaid dividends. Prior to the redemption and as of December 31, 2000, there were 75,000 shares outstanding.

The loss on redemption of \$1.2 million is reflected as a reduction to reconcile net income to net income applicable to common shareholder. The total redemption price was \$17.7 million.

Redeemable, Special

This series of redeemable preferred stock has a dividend rate of 8.50% and in the event of involuntary liquidation the amount payable is \$100 per share, plus accrued dividends. This Series may be redeemed at \$100 per share, plus accrued dividends on any of its dividend payment dates and is also callable at the Company's option at a rate of 1,160 shares per year. As of December 31, 2002 and 2001, there were 3,437 shares and 4,597 shares outstanding, respectively.

9. Commitments and Contingencies

Commitments

Firm commitments to purchase natural gas for years following December 31, 2002 totaled (in millions) \$18.4 in 2003, \$6.1 in 2004, and \$1.2 in 2005.

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. See Note 10 regarding the Clean Air Act.

10. Environmental Matters

Clean Air Act

NOx SIP Call Matter

The Clean Air Act (the Act) requires each state to adopt a State Implementation Plan (SIP) to attain and maintain National Ambient Air Quality Standards (NAAQS) for a number of pollutants, including ozone. If the USEPA finds a state's SIP inadequate to achieve the NAAQS, the USEPA can call upon the state to revise its SIP (a SIP Call).

In October 1998, the USEPA issued a final rule "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone," (63 Fed. Reg. 57355). This ruling found that the SIP's of certain states, including Indiana, were substantially inadequate since they allowed for nitrogen oxide (NOx) emissions in amounts that contributed to non-attainment with the ozone NAAQS in downwind states. The USEPA required each state to revise its SIP to provide for further NOx emission reductions. The NOx emissions budget, as stipulated in the USEPA's final ruling, requires a 31% reduction in total NOx emissions from Indiana.

In June 2001, the Indiana Air Pollution Control Board adopted final rules to achieve the NOx emission reductions required by the NOx SIP Call. Indiana's SIP requires the Company to lower its system-wide NOx emissions to .14

lbs./MMBTU by May 31, 2004 (the compliance date). This is a 65% reduction from emission levels existing in 1999 and 1998.

The Company has initiated steps toward compliance with the revised regulations. These steps include installing 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 NO_x emissions to atmospheric nitrogen and water using ammonia in a chemical reaction. This technology is known to be the most effective method of reducing NO_x emissions where high removal efficiencies are required.

On August 28, 2001, the IURC issued an order that (1) approved the Company's proposed project to achieve environmental compliance by investing in clean coal technology, (2) approved the Company's initial cost estimate of \$198 million for the construction, subject to periodic review of the actual costs incurred, and (3) approved a mechanism whereby, prior to an electric base rate case, the Company may recover through a rider that is updated every six months a return on its capital costs for the project, at its overall cost of capital, including a return on equity. The first rider adjustment for ongoing cost recovery was approved by the IURC on February 6, 2002. Based on the level of system-wide emissions reductions required and the control technology utilized to achieve the reductions, the current estimated clean coal technology construction cost ranges from \$240 million to \$250 million and is expected to be expended during the 2001-2006 period. Through December 31, 2002, \$70.0 million has been expended.

On June 5, 2002, the Company filed a new proceeding to update the NO_x project cost and to obtain approval of a second rider authorizing ongoing recovery of depreciation and operating costs related to the clean coal technology. After the equipment is installed and operational, related annual operating expenses, including depreciation expense, are estimated to be between \$24 million and \$27 million. Such expenses would commence in 2004 when the technology becomes operational. On January 3, 2003, the IURC approved a settlement that authorizes total capital cost investment for this project up to \$244 million (excluding AFUDC) and recovery on those capital costs, as well as the recovery of future operating costs, including depreciation and purchased emission allowances, through a rider mechanism. The settlement establishes a fixed return of 8 percent on the capital investment, which approximates the return authorized in the Company's last electric rate case in 1995.

The Company expects to achieve timely compliance as a result of the project. Construction of the first SCR at Culley is nearing completion on schedule, and installation of SCR technology as planned is expected to reduce the Company's overall NO_x emissions to levels compliant with Indiana's NO_x emissions budget allotted by the USEPA. Therefore, the Company has recorded no accrual for potential penalties that may result from noncompliance.

Culley Generating Station Litigation

In the late 1990's, the USEPA initiated an investigation under Section 114 of the Act of SIGECO's coal-fired electric generating units in commercial operation by 1977 to determine compliance with environmental permitting requirements related to repairs, maintenance, modifications, and operations changes. The focus of the investigation was to determine whether new source review permitting requirements were triggered by such plant modifications, and whether the best available control technology was, or should have been used. Numerous electric utilities were, and are currently, being investigated by the USEPA under an industry-wide review for compliance. In July 1999, SIGECO received a letter from the Office of Enforcement and Compliance Assurance of the USEPA discussing the industry-wide investigation, vaguely referring to an investigation of SIGECO and inviting SIGECO to participate in a discussion of the issues. No specifics were noted; furthermore, the letter stated that the communication was not intended to serve as a notice of violation. Subsequent meetings were conducted in September and October 1999 with the USEPA and targeted utilities, including SIGECO, regarding potential remedies to the USEPA's general allegations.

On November 3, 1999, the USEPA filed a lawsuit against seven utilities, including SIGECO. The USEPA alleges that, beginning in 1992, SIGECO violated the Act by (1) making modifications to its Culley Generating Station in Yankeetown, Indiana without obtaining required permits (2) making major modifications to the Culley Generating Station without installing the best available emission control technology and (3) failing to notify the USEPA of the

modifications. In addition, the lawsuit alleges that the modifications to the Culley Generating Station required SIGECO to begin complying with federal new source performance standards at its Culley Unit 3.

SIGECO believes it performed only maintenance, repair, and replacement activities at the Culley Generating Station, as allowed under the Act. Because proper maintenance does not require permits, application of the best available control technology, notice to the USEPA, or compliance with new source performance standards, SIGECO believes that the lawsuit is without merit, and intends to vigorously defend itself. Since the filing of this lawsuit, the USEPA has voluntarily dismissed a majority of the claims brought in its original complaint. In its original complaint, USEPA alleged significant emissions increases of three pollutants for each of four maintenance projects. Currently, USEPA is alleging only significant emission increases of a single pollutant at three of the four maintenance projects cited in the original complaint.

The lawsuit seeks fines against SIGECO in the amount of \$27,500 per day per violation. However, on July 29, 2002, the Court ruled that USEPA could not seek civil penalties for two of the three remaining projects at issue in the litigation, significantly reducing potential civil penalty exposure. The lawsuit also seeks a court order requiring SIGECO to install the best available emissions technology at the Culley Generating Station. If the USEPA were successful in obtaining an order, SIGECO estimates that in response it could incur capital costs of approximately \$20 million to \$40 million to comply with the order. Trial is currently set to begin July 14, 2003.

The USEPA has also issued an administrative notice of violation to SIGECO making the same allegations, but alleging that violations began in 1977.

While it is possible that SIGECO could be subjected to criminal penalties if the Culley Generating Station continues to operate without complying with the permitting requirements of new source review and the allegations are determined by a court to be valid, SIGECO believes such penalties are unlikely as the USEPA and the electric utility industry have a bonafide dispute over the proper interpretation of the Act. Accordingly, the Company has recorded no accrual and the plant continues to operate while the matter is being decided.

Information Request

On January 23, 2001, SIGECO received an information request from the USEPA under Section 114 of the Act for historical operational information on the Warrick and A.B. Brown generating stations. SIGECO has provided all information requested, and no further action has occurred.

Manufactured Gas Plants

In October 2002, the Company received a formal information request letter from the IDEM regarding five manufactured gas plants owned and/or operated by SIGECO and not currently enrolled the IDEM's Voluntary Remediation Program. 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 risk to human health or the environment. Follow up reviews have recently been initiated by the Company to confirm that the sites continue to pose no such risk.

11. Rate and Regulatory Matters

Gas Costs Proceedings

Commodity prices for natural gas purchases were significantly higher during the 2000 - 2001 heating season, primarily due to colder temperatures, increased demand and tighter supplies. Subject to compliance with applicable state laws, Vectren's utility subsidiaries are allowed full recovery of such changes in purchased gas costs from their retail customers through commission-approved gas cost adjustment mechanisms.

In March 2001, Indiana Gas and SIGECO reached agreement with the OUCC and the Citizens Action Coalition of Indiana, Inc. (CAC) regarding the matters raised by an IURC Order that disallowed \$3.8 million of Indiana Gas' gas procurement costs for the 2000 – 2001 heating season which was recognized during the year ended December 31, 2000. As part of the agreement, the companies agreed to contribute an additional \$1.7 million to assist qualified low income gas customers, and Indiana Gas agreed to credit \$3.3 million of the \$3.8 million disallowed amount to

its customers' April 2001 utility bills in exchange for both the OUCC and the CAC dropping their appeals of the IURC Order. In April 2001, the IURC issued an order approving the settlement. Substantially all of the financial assistance for low income gas customers was distributed in 2001.

Purchased Power Costs

As a result of an appeal of a generic order issued by the IURC in August 1999 regarding guidelines for the recovery of purchased power costs, SIGECO entered into a settlement agreement with the OUCC that provides certain terms with respect to the recoverability of such costs. The settlement, originally approved by the IURC in August 2000, has been extended by agreement through March 2003, and discussions regarding further extension of the settlement term are ongoing. Under the settlement, SIGECO can recover the entire cost of purchased power up to an established benchmark, and during forced outages, SIGECO will bear a limited share of its purchased power costs regardless of the market costs at that time. Based on this agreement, SIGECO believes it has limited its exposure to unrecoverable purchased power costs.

12. Risk Management, Derivatives, and Other Financial Instruments

The Company is exposed to various business risks associated with commodity prices, interest rates, and counterparty 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 to mitigate risk.

The Company also executes derivative contracts in the normal course of operations while buying and selling commodities and other fungible goods to be used in operations and while optimizing generation assets. The Company does not execute derivative contracts for speculative or trading purposes.

Commodity Price Risk

The Company's regulated operations have limited exposure to commodity price risk for purchases and sales of natural gas and electricity for its 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.

Electric sales and purchases in the wholesale power market and other commodity-related operations are exposed to commodity price risk associated with fluctuating electric power and other commodity prices. Other commodity operations include sales of electricity to certain municipalities and large industrial customers.

The Company's non-firm wholesale power marketing operations manage the utilization of its available electric generating capacity by entering into forward and option 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's other commodity-related operations involve the purchase and sale of commodities, including electricity, to meet customer demands and operational needs. These operations also enter into forward contracts that commit the Company to purchase and sell commodities in the future. Price risk from forward positions that commit the Company to deliver commodities is mitigated using insurance contracts and offsetting forward purchase contracts.

Open positions in terms of price, volume, and specified delivery points may occur and are managed using methods described above and frequent management reporting.

Interest Rate Risk

The Company is exposed to interest rate risk associated with its adjustable rate borrowing arrangements. Its risk management program seeks to reduce the potentially adverse effects that market volatility may have on operations. The Company tries to limit the amount of adjustable rate borrowing arrangements exposed to short-term interest

rate volatility to a maximum of 25% of total debt. However, there are times when this targeted level of interest rate exposure may be exceeded. To manage this exposure, the Company may periodically use derivative financial instruments to reduce earnings fluctuations caused by interest rate volatility.

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. 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.

Although the Company'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.

Accounting for Derivatives and Other Contracts

When a derivative contract that is entered into in the normal course of operations is probable of physical settlement, that contract is designated and documented as a normal purchase or normal sale and is exempted from mark-to-market accounting. Otherwise, derivative contracts are recorded at market value as current or noncurrent assets or liabilities depending on their value and on when the contracts are expected to be settled. Unless the contract is a cash flow hedge that qualifies for hedge accounting treatment or is subject to SFAS 71, that contract is marked to market through earnings. When hedge accounting is appropriate, the Company assesses and documents hedging relationships between its financial instruments, including commodity contracts and interest rate swaps, and underlying risks as well as the investment's 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. The ineffective portion of hedging arrangements is marked to market through earnings. Contracts affected by SFAS 71 are marked to market as a regulatory asset or liability. Market value is determined using quoted market prices from independent sources.

Non-Firm Wholesale Power Marketing Contracts

Periodically, generation capacity is in excess of that needed to serve retail and firm wholesale customers. The Company markets this unutilized capacity to optimize the return on its owned generation assets. The contracts entered into are primarily short-term purchase and sale contracts that expose the Company to limited market risk and are settled both financially and physically. These operations do not meet the definition of energy trading activities based upon the provisions in EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10).

Asset optimization sale contracts are reflected in electric utility revenues, and purchase contracts are reflected in purchased electric energy. Contracts with counter-parties subject to master netting arrangements are presented net in the Balance Sheets. Subsequent to the adoption of SFAS 133 as described below, certain non-firm power marketing contracts that are periodically financially settled are recorded at market value. Changes in market value, which is a function of the normal decline in market value as earnings are realized and the fluctuation in market value resulting from price volatility, are recorded in purchased electric energy.

Power marketing contracts recorded at market value at December 31, 2002 totaled \$3.5 million of prepayments and other current assets and \$4.2 million of accrued liabilities, compared to \$6.1 million of prepayments and other current assets and \$2.8 million of accrued liabilities at December 31, 2001. The change in the net value of these contracts includes an unrealized loss of \$3.6 million in 2002 and an unrealized gain of \$1.5 million in 2001, respectively. Including these unrealized changes in market value, overall margin (revenue net of purchased power) from non-firm wholesale power marketing operations for the years ended December 31, 2002 and 2001 was \$14.9 million and \$19.9 million, respectively. Prior to the adoption of SFAS 133 and for the year ended December 31, 2000, margin was \$21.1 million.

Other Commodity-Related Operations

Other commodity contracts are generally settled by physical delivery or receipt and are within the normal operations of the Company. Therefore, these contracts receive accounting recognition upon settlement. Firm wholesale electric contracts are recorded in electric utility revenues. Certain contracts that purchase commodities for operational needs are recorded when settled in other operating expenses.

Impact of Adoption of SFAS 133

In June 1998, the FASB issued SFAS 133, which required that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its market value and that changes in the derivative's market value be recognized currently in earnings unless specific hedge or regulatory accounting criteria are met.

SFAS 133, as amended, required that as of the date of initial adoption, the difference between the market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivatives be reported in net income, other comprehensive income, or regulatory assets or liabilities, as appropriate. A change in earnings or other comprehensive income was reported as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes."

Resulting from the adoption of SFAS 133, certain non-firm wholesale power marketing contracts that are periodically settled net were required to be recorded at market value. Previously, the Company accounted for these contracts on settlement. The cumulative impact of the adoption of SFAS 133 resulting from marking these contracts to market on January 1, 2001 was an earnings gain of approximately \$1.8 million (\$1.1 million net of tax) recorded as a cumulative effect of accounting change. SFAS 133 did not impact other commodity contracts because they were normal purchases and sales specifically excluded from the provisions of SFAS 133.

Fair Value of Other Financial Instruments

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

In thousands	At December 31,			
	2002		2001	
	Carrying Amount	Est. Fair Value	Carrying Amount	Est. Fair Value
Long term debt	\$ 294,615	\$313,202	\$ 294,615	\$ 289,179
Long term debt due to VUHI	86,574	93,820	49,460	49,460
Short-term borrowings & notes payable	-	-	874	874
Short-term debt due to VUHI	39,419	39,419	80,664	80,664

Certain methods and assumptions must be used to estimate the fair value of financial instruments. The fair value of the Company's other financial instruments 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.

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. Accordingly, any reacquisition would not be expected to have a material effect on the Company's financial position or results of operations.

13. Additional Operational and Balance Sheet Information

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

In thousands	Year ended December 31,		
	2002	2001	2000
AFUDC	\$ 3,679	\$ 3,024	\$ 3,868
Other income	2,394	5,923	1,415
Other expense	(1,279)	(3,318)	(609)
Total other – net	\$ 4,794	\$ 5,629	\$ 4,674

Accrued liabilities in the Balance Sheets consists of the following:

In thousands	At December 31,	
	2002	2001
Accrued taxes	\$ 8,707	\$ 11,833
Deferred income taxes	4,680	7,207
Accrued interest	5,593	5,510
Refunds to customers & customer deposits	4,576	3,470
Accrued salaries & other	7,157	2,657
Total accrued liabilities	\$30,713	\$ 30,677

14. Segment Reporting

The Company has two operating segments: (1) Gas Utility Services and (2) Electric Utility Services. The Gas Utility Services segment includes the operations of the Company's natural gas distribution business and provides natural gas distribution and transportation services in southwest Indiana. The Electric Utility Services segment includes the operations of the Company's power generating and marketing operations, and electric transmission and distribution services, which provides electricity to primarily southwestern Indiana. The following tables provide information about business segments. The Company makes decisions on finance and dividends at the corporate level.

In thousands	Year ended December 31,		
	2002	2001	2000
Operating Revenues			
Electric Utility Services	\$ 608,116	\$ 381,233	\$ 334,428
Gas Utility Services	85,461	98,580	109,142
Total operating revenues	\$ 693,577	\$ 479,813	\$ 443,570
Interest Expense			
Electric Utility Services	\$ 19,723	\$ 17,813	\$ 18,102
Gas Utility Services	3,445	3,111	1,791
Total interest expense	\$ 23,168	\$ 20,924	\$ 19,893

	Year ended December 31,		
In thousands	2002	2001	2000
Income Taxes			
Electric Utility Services	\$ 28,508	\$ 21,203	\$ 23,386
Gas Utility Services	2,129	445	1,039
Total income taxes	\$ 30,637	\$ 21,648	\$ 24,425
Net Income applicable to common shareholder			
Electric Utility Services	\$ 56,408	\$ 43,074	\$ 36,811
Gas Utility Services	2,919	(2,392)	2,555
Net income	\$ 59,327	\$ 40,682	\$ 39,366
Depreciation & Amortization			
Electric Utility Services	\$ 40,003	\$ 38,691	\$ 38,639
Gas Utility Services	5,095	4,596	4,575
Total depreciation & amortization	\$ 45,098	\$ 43,287	\$ 43,214
Capital Expenditures			
Electric Utility Services	\$ 87,544	\$ 69,683	\$ 43,520
Gas Utility Services	2,203	8,077	7,599
Total capital expenditures	\$ 89,747	\$ 77,760	\$ 51,119

	At December 31,	
In thousands	2002	2001
Identifiable Assets		
Electric Utility Services	\$ 856,516	\$ 804,867
Gas Utility Services	169,142	175,025
Total identifiable assets	\$ 1,025,658	\$ 979,892

15. Special Charges for 2001 and 2000

Restructuring and Related Charges

As part of continued cost saving efforts, in June 2001, Vectren's management and board of directors approved a plan to restructure, primarily, its regulated operations. The restructuring plan included the elimination of certain administrative and supervisory positions in its utility operations and corporate office. Charges of \$4.3 million were expensed in June 2001 as a direct result of the restructuring plan. Additional charges of \$1.5 million were incurred during the remainder of 2001 primarily for consulting fees and employee relocation costs. In total, the Company has incurred restructuring charges of \$5.8 million. These charges were comprised of \$4.4 million for employee severance, related benefits and other employee related costs, and \$1.4 million for consulting and other fees incurred through December 31, 2001.

The \$4.4 million expensed for employee severance and related costs includes \$0.8 million of noncash pension costs and is associated with approximately 40 employees. Employee separation benefits include severance, healthcare, and outplacement services. As of December 31, 2001, 37 employees have exited the business. Restructuring expenses were incurred by the Company's operating segments as follows: \$1.0 million by the Gas Utility Services segment and \$4.8 million by the Electric Utility Services segment. The restructuring program was completed

during 2001, except for the departure of the remaining employees impacted by the restructuring which occurred during 2002.

In June 2001, the Company established accruals totaling \$2.7 million for severance. Throughout 2001 additional expenses totaling \$0.6 million for severance were incurred. Cash payments in 2001 totaled \$3.1 million. As of December 31, 2001, the remaining accrual related to the restructuring was \$0.2 million. Of that amount, almost all relates to structured compensation arrangements payable through 2004. During 2002, the accrual for severance did not substantially change.

Merger and Integration Costs

Merger and integration costs incurred for the years ended December 31, 2001 and 2000 were \$0.6 million and \$14.1 million, respectively. Merger and integration activities resulting from the 2000 merger were completed in 2001. Merger costs are reflected in the financial statements of the operating subsidiaries in which merger savings are expected to be realized.

Since March 31, 2000, \$14.7 million has been expensed associated with merger and integration activities. Accruals were established at March 31, 2000 totaling \$7.4 million. Of this amount, \$0.7 million related to employee and executive severance costs and \$6.7 million related to transaction costs and regulatory filing fees incurred prior to the closing of the merger. At December 31, 2001, no accrual remains. The remaining \$7.3 million was expensed (\$6.7 million in 2000 and \$0.6 million in 2001) for accounting fees resulting from merger related filing requirements, consulting fees related to integration activities such as organization structure, employee travel between company locations, internal labor of employees assigned to integration teams, investor relations communication activities, and certain benefit costs.

During the merger planning process, approximately 54 positions were identified for elimination. As of December 31, 2001, all such identified positions have been vacated.

The integration activities experienced by the Company included such things as information system consolidation, process review and definition, organization design and consolidation, and knowledge sharing.

16. Impact of Recently Issued Accounting Guidance

EITF 02-03

In October 2002, the EITF reached a final consensus in EITF Issue 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03) that gains and losses (realized and unrealized) on all derivative instruments within the scope of SFAS 133 should be shown net in the income statement, whether or not settled physically, if the derivative instruments are held for "trading purposes." The consensus rescinded EITF Issue 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10) as well as other decisions reached on energy trading contracts at the EITF's June 2002 meeting.

The Company's non-firm wholesale power marketing operations enter into contracts that are derivatives as defined by SFAS 133, but these operations do not meet the definition of energy trading activities based upon the provisions in EITF 98-10. Currently, the Company uses a gross presentation to report the results of these operations as described in Note 12. The Company has re-evaluated its portfolio of derivative contracts and has determined gross presentation remains appropriate.

SFAS 143

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation 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 to its present value, 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 upon settlement. Any costs of removal recorded in

accumulated depreciation pursuant to regulatory authority will require disclosure in future periods. The Company adopted this statement on January 1, 2003. The adoption was not material to the Company's results of operations or financial condition.

FASB Interpretation (FIN) 45

In November 2002, the FASB issued Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 clarifies the requirements for a guarantor's accounting for and disclosure of certain guarantees issued and outstanding and that a guarantor is required to recognize, at the inception of a guarantee, a liability for the obligations it has undertaken. The objective of the initial measurement of that liability is the fair value of the guarantee at its inception. The initial recognition and measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. Although management is still evaluating the impact of FIN 45 on its financial position and results of operations, the adoption is not expected to have a material effect.

FIN 46

In January 2003, the FASB issued Interpretation 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 addresses consolidation by business enterprises of variable interest entities and significantly changes the consolidation requirements for those entities. FIN 46 is intended to achieve more consistent application of consolidation policies to variable interest entities and, thus improves comparability between enterprises engaged in similar activities when those activities are conducted through variable interest entities. FIN 46 applies to variable interest entities created after January 31, 2003 and to variable interest entities in which an enterprise obtains an interest after that date. FIN 46 applies to the Company's third quarter for variable interest entities in which the Company holds a variable interest acquired before February 1, 2003. Although management is still evaluating the impact of FIN 46 on its financial position and results of operations, the adoption is not expected to have a material effect.

17. Quarterly Financial Data (Unaudited)

As more fully described in Note 3, the Company has restated the results for the year ended December 31, 2001, including each quarter, as well as the first three quarters of 2002 to appropriately account for certain transactions. Provided below is a comparison of restated summarized quarterly financial data to summarized quarterly financial data previously reported. Information in any one quarterly period is not indicative of annual results due to the seasonal variations common to the Company's utility operations.

Summarized quarterly financial data for 2002 follows:

In thousands	Q1		Q2 (5)		Q3		Q4
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported
2002 Operating data							
Operating revenues	\$ 156,407	\$156,407	\$176,548	\$176,548	\$197,323	\$197,018	\$163,604
Operating margin	61,249	61,207	59,073	59,290	79,541	78,766	63,328
Operating income	15,830	15,738	11,002	13,225	27,628	27,015	21,756
Net income applicable to common shareholder	11,137	11,435	12,384	9,439	22,826	22,212	16,241

Summarized quarterly financial data for 2001 follows:

In thousands	Q1 (1)		Q2 (2)		Q3		Q4 (4)	
	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated	As Reported	As Restated
2001 Operating Data (3)								
Operating revenues	\$ 140,159	\$141,305	\$106,371	\$106,867	\$115,367	\$116,289	\$118,087	\$115,352
Operating margin	67,564	71,054	50,323	52,112	65,865	69,627	57,335	52,978
Operating income	19,984	21,590	5,669	6,741	18,973	21,280	11,041	7,187
Income before cumulative effect of change in accounting principle	15,587	17,120	1,480	2,447	14,692	16,961	8,693	4,975
Net income applicable to common shareholder	19,287	17,989	1,238	2,205	13,248	15,523	8,689	4,965

1. Q1 of 2001 includes charges for cumulative effect of changes in accounting principle as described in Note 12.
2. Q2 of 2001 includes restructuring charges as described in Note 15.
3. 2001 includes merger and integration charges as described in Note 15.
4. The benefit clearing adjustment and the inventory adjustment discussed in Note 3 were recorded in Q4 of 2001.
5. In Q2 of 2002, the Company recorded \$3.2 million of after tax carrying costs for DSM programs pursuant to existing IURC orders. Management determined that the accrual of such carrying costs was more appropriate in periods prior to 2000 when DSM program expenditures were made. Therefore, such carrying costs originally reflected in Q2 of 2002 were reversed and reflected in common shareholder's equity as of January 1, 2000.

ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Disclosure with respect to this Item, has been previously provided on Form 8-K originally filed with the SEC on March 26, 2002, as amended on Form 8-K/A filed with the SEC on May 20, 2002.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

ITEM 11. EXECUTIVE COMPENSATION

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Intentionally omitted. See the table of contents of this Annual Report on Form 10-K for explanation.

PART IV

ITEM 14. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Within 90 days prior to the filing of the report, the Company carried out an evaluation under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the effectiveness and the design and operation of the Company's disclosure controls and procedures. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective in bringing to their attention on a timely basis material information relating to the Company required to be disclosed by the Company in its filings under the Securities Exchange Act of 1934 (Exchange Act).

Disclosure controls and procedures, as defined by the Exchange Act in Rules 13a-14(c) and 15d-14(c), are controls and other procedures of the Company that are designed to ensure that information required to be disclosed by the Company in the reports filed or submitted by it under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms. "Disclosure controls and procedures" include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Company in its Exchange Act reports is accumulated and communicated to the Company's management, including its principal executive and financial officers, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control

Since the evaluation of disclosure controls and procedures, there have been no significant changes to the Company's internal controls and procedures or significant changes in other factors that could significantly affect the Company's internal controls and procedures. However, in Note 3 to the financial statements (included in Item 8) which discusses the restatement of 2001 and 2000 previously reported information, the Company identified certain errors, the net effect of which, related primarily to gas inventory accounting and the proper clearing of employee benefit related costs routinely accumulated on the balance sheet. These errors resulted primarily from insufficient account reconciliation procedures. The Company has taken steps to improve these internal controls.

Internal control, as defined in American Institute of Certified Public Accountants Codification of Statements on Auditing Standards (AU §319), is a process, effected by an entity's board of directors, management, and other personnel, designed to provide reasonable assurance regarding the achievement of objectives in the following categories: (a) reliability of financial reporting, (b) effectiveness and efficiency of operations and (c) compliance with applicable laws and regulations.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

List Of Documents Filed As Part Of This Report

Financial Statements

The financial statements and related notes, together with the report of Deloitte & Touche LLP, appear in Part II Item 8 Financial Statements and Supplementary Data of this Form 10-K.

Supplemental Schedules

For the years ended December 31, 2002, 2001, and 2000, the Company's Schedule II -- Valuation and Qualifying Accounts Financial Statement Schedules is presented on page 47. The report of Deloitte & Touche LLP on the schedule may be found in Item 8.

All other schedules are omitted as the required information is inapplicable or the information is presented in the Financial Statements or related notes in Item 8.

List of Exhibits

The Company has incorporated by reference herein certain exhibits as specified below pursuant to Rule 12b-32 under the Exchange Act.

Exhibits for the Company are listed in the Index to Exhibits beginning on page 52.

Exhibits for the Company attached to this filing filed electronically with the SEC are listed on page 57.

Reports On Form 8-K During The Last Calendar Quarter

On October 25, 2002, the Company filed a Current Report on Form 8-K with respect to the release of financial information to the investment community regarding Vectren Corporation's results of operations, financial position and cash flows for the three, nine, and twelve month periods ended September 30, 2002. The financial information was released to the public through this filing.

Item 5. Other Events

Item 7. Exhibits

99.1 – Press Release - Third Quarter 2002 Vectren Corporation Earnings

99.2 – Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

On November 27, 2002, the Company filed a Current Report on Form 8-K with respect to a press release issued by Moody's Investor Services that downgraded the credit ratings on various debt instruments issued by certain of Vectren Corporation's (Vectren) wholly owned subsidiaries.

Item 5. Other Events

Item 7. Exhibits

99.1 – Press Release - Moody's Investor's Services

99.2 – Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

SCHEDULE II

Southern Indiana Gas and Electric Company

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning Of Year	Additions		Deductions from Reserves, Net	Balance at End of Year
		Charged to Expenses	Charged to Other Accounts		
(In thousands)					
VALUATION AND QUALIFYING ACCOUNTS:					
Year 2002 – Accumulated provision for uncollectible accounts	\$ 3,188	\$ 2,500	\$ -	\$ 2,026	\$ 3,662
Year 2001 – Accumulated provision for uncollectible accounts	\$ 2,639	\$ 2,387	\$ -	\$ 1,838	\$ 3,188
Year 2000 – Accumulated provision for uncollectible accounts	\$ 2,138	\$ 1,189	\$ -	\$ 688	\$ 2,639
OTHER RESERVES:					
Year 2001 – Reserve for merger and integration charges	\$ 526	\$ -	\$ -	\$ 526	\$ -
Year 2000 – Reserve for merger and integration charges	\$ -	\$ 7,400	\$ -	\$ 6,874	\$ 526
Year 2002 – Reserve for restructuring costs	\$ 180	\$ -	\$ 670	\$ -	\$ 850
Year 2001 – Reserve for restructuring costs	\$ -	\$ 3,321	\$ -	\$ 3,141	\$ 180

SIGNATURES

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

SOUTHERN INDIANA GAS
AND ELECTRIC COMPANY

Dated February 26, 2003

/S/ Niel C. Ellerbrook
Niel C. Ellerbrook, Chairman and
Chief Executive Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in capacities and on the dates indicated.

Signature	Title	Date
<u>/S/ Niel C. Ellerbrook</u> Niel C. Ellerbrook	Chairman & Chief Executive Officer, Director (Principal Executive Officer)	<u>February 26, 2003</u>
<u>/S/ Jerome A. Benkert, Jr.</u> Jerome A. Benkert, Jr.	Executive Vice President, Chief Financial Officer, & Director (Principal Financial Officer)	<u>February 26, 2003</u>
<u>/S/ M. Susan Hardwick</u> M. Susan Hardwick	Vice President & Controller, Director (Principal Accounting Officer)	<u>February 26, 2003</u>
<u>/S/ Andrew E. Goebel</u> Andrew E. Goebel	Director	<u>February 26, 2003</u>
<u>/S/ Ronald E. Christian</u> Ronald E. Christian	Director	<u>February 26, 2003</u>
<u>/S/ William S. Doty</u> William S. Doty	Director	<u>February 26, 2003</u>

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

CHIEF EXECUTIVE OFFICER CERTIFICATION

I, Niel C. Ellerbrook, certify that:

1. I have reviewed this annual report on Form 10-K of Southern Indiana Gas and Electric Company;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
 - a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
 - c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 26, 2003

/s/ Niel C. Ellerbrook

Niel C. Ellerbrook
Chairman and Chief Executive Officer

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

CHIEF FINANCIAL OFFICER CERTIFICATION

I, Jerome A. Benkert, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Southern Indiana Gas and Electric Company;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:
 - a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and
 - c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 26, 2003

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

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

CERTIFICATION

By signing below, each of the undersigned officers hereby certifies pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his or her knowledge, (i) this report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in this report fairly presents, in all material respects, the financial condition and results of operations of Southern Indiana Gas and Electric Company.

Signed this 26th day of February, 2003.

/s/ Jerome A. Benkert, Jr.
(Signature of Authorized Officer)

/s/ Niel C. Ellerbrook
(Signature of Authorized Officer)

Jerome A. Benkert, Jr.
(Typed Name)

Niel C. Ellerbrook
(Typed Name)

Executive Vice President and Chief
Financial Officer
(Title)

Chairman and Chief Executive Officer
(Title)

INDEX TO EXHIBITS

2. Plan Of Acquisition, Reorganization, Arrangement, Liquidation Or Succession

Not applicable.

3. Articles Of Incorporation And By-Laws

- 3.1 Amended and Restated Articles of Incorporation of Southern Indiana Gas and Electric Company effective January 24, 2003. (Filed herewith.)
- 3.2 Amended and Restated Code of By-Laws of Southern Indiana Gas and Electric Company as of January 16, 2003. (Filed herewith.)

4. Instruments Defining The Rights Of Security Holders, Including Indentures

- 4.1 Mortgage and Deed of Trust dated as of April 1, 1932 between Southern Indiana Gas and Electric Company and Bankers Trust Company, as Trustee, and Supplemental Indentures thereto dated August 31, 1936, October 1, 1937, March 22, 1939, July 1, 1948, June 1, 1949, October 1, 1949, January 1, 1951, April 1, 1954, March 1, 1957, October 1, 1965, September 1, 1966, August 1, 1968, May 1, 1970, August 1, 1971, April 1, 1972, October 1, 1973, April 1, 1975, January 15, 1977, April 1, 1978, June 4, 1981, January 20, 1983, November 1, 1983, March 1, 1984, June 1, 1984, November 1, 1984, July 1, 1985, November 1, 1985, June 1, 1986. (Filed and designated in Registration No. 2-2536 as Exhibits B-1 and B-2; in Post-effective Amendment No. 1 to Registration No. 2-62032 as Exhibit (b)(4)(ii), in Registration No. 2-88923 as Exhibit 4(b)(2), in Form 8-K, File No. 1-3553, dated June 1, 1984 as Exhibit (4), File No. 1-3553, dated March 24, 1986 as Exhibit 4-A, in Form 8-K, File No. 1-3553, dated June 3, 1986 as Exhibit (4).) July 1, 1985 and November 1, 1985 (Filed and designated in Form 10-K, for the fiscal year 1985, File No. 1-3553, as Exhibit 4-A.) November 15, 1986 and January 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1986, File No. 1-3553, as Exhibit 4-A.) December 15, 1987. (Filed and designated in Form 10-K, for the fiscal year 1987, File No. 1-3553, as Exhibit 4-A.) December 13, 1990. (Filed and designated in Form 10-K, for the fiscal year 1990, File No. 1-3553, as Exhibit 4-A.) April 1, 1993. (Filed and designated in Form 8-K, dated April 13, 1993, File No. 1-3553, as Exhibit 4.) June 1, 1993 (Filed and designated in Form 8-K, dated June 14, 1993, File No. 1-3553, as Exhibit 4.) May 1, 1993. (Filed and designated in Form 10-K, for the fiscal year 1993, File No. 1-3553, as Exhibit 4(a).) July 1, 1999. (Filed and designated in Form 10-Q, dated August 16, 1999, File No. 1-3553, as Exhibit 4(a).) March 1, 2000. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 4.1.)
- 4.2 Indenture dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.1); First Supplemental Indenture, dated October 19, 2001, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated October 19, 2001, File No. 1-16739, as Exhibit 4.2); Second Supplemental Indenture, between Vectren Utility Holdings, Inc., Indiana Gas Company, Inc., Southern Indiana Gas and Electric Company, Vectren Energy Delivery of Ohio, Inc., and U.S. Bank Trust National Association. (Filed and designated in Form 8-K, dated November 29, 2001, File No. 1-16739, as Exhibit 4.1).
- 4.3 Promissory Note for Long-Term Loans dated November 30, 2001, between Southern Indiana Gas and Electric Company and Vectren Utility Holdings, Inc. (Filed and designated in Form 10-K, for the year ended December 31, 2001, File No. 1-3553, as Exhibit 4.4).

- 4.4 Promissory Note for Long-Term Loans dated December 1, 2002, between Southern Indiana Gas and Electric Company and Vectren Utility Holdings, Inc. (Filed herewith.)

9. Voting Trust Agreement

Not applicable.

10. Material Contracts

- 10.1 Agreement, dated, January 30, 1968, for Unit No. 4 at the Warrick Power Plant of Alcoa Generating Corporation ("Alcoa"), between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-29653 as Exhibit 4(d)-A.)
- 10.2 Letter of Agreement, dated June 1, 1971, and Letter Agreement, dated June 26, 1969, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-41209 as Exhibit 4(e)-2.)
- 10.3 Letter Agreement, dated April 9, 1973, and Agreement dated April 30, 1973, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-53005 as Exhibit 4(e)-4.)
- 10.4 Electric Power Agreement (the "Power Agreement"), dated May 28, 1971, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Registration No. 2-41209 as Exhibit 4(e)-1.)
- 10.5 Second Supplement, dated as of July 10, 1975, to the Power Agreement and Letter Agreement dated April 30, 1973 - First Supplement. (Filed and designated in Form 10-K for the fiscal year 1975, File No. 1-3553, as Exhibit 1(e).)
- 10.6 Third Supplement, dated as of May 26, 1978, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1978 as Exhibit A-1.)
- 10.7 Letter Agreement dated August 22, 1978 between Southern Indiana Gas and Electric Company and Alcoa, which amends Agreement for Sale in an Emergency of Electrical Power and Energy Generation by Alcoa and Southern Indiana Gas and Electric Company dated June 26, 1979. (Filed and designated in Form 10-K for the fiscal year 1978, File No. 1-3553, as Exhibit A-2.)
- 10.8 Fifth Supplement, dated as of December 13, 1978, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-3.)
- 10.9 Sixth Supplement, dated as of July 1, 1979, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-5.)
- 10.10 Seventh Supplement, dated as of October 1, 1979, to the Power Agreement. (Filed and designated in Form 10-K for the fiscal year 1979, File No. 1-3553, as Exhibit A-6.)
- 10.11 Eighth Supplement, dated as of June 1, 1980 to the Electric Power Agreement, dated May 28, 1971, between Alcoa and Southern Indiana Gas and Electric Company. (Filed and designated in Form 10-K for the fiscal year 1980, File No. 1-3553, as Exhibit (20)-1.)
- 10.12 Amendment Agreement, dated March 3, 2001, between Alcoa Power Generating Inc. and Southern Indiana Gas and Electric Company. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.12.)

- 10.13 Summary description of Southern Indiana Gas and Electric Company's nonqualified Supplemental Retirement Plan (Filed and designated in Form 10-K for the fiscal year 1992, File No. 1-3553, as Exhibit 10-A-17.)
- 10.14 Southern Indiana Gas and Electric Company 1994 Stock Option Plan (Filed and designated in Southern Indiana Gas and Electric Company's Proxy Statement dated February 22, 1994, File No. 1-3553, as Exhibit A.)
- 10.15 Southern Indiana Gas and Electric Company's nonqualified Supplemental Retirement Plan as amended, effective April 16, 1997. (Filed and designated in Form 10-K for the fiscal year 1997, File No. 1-3553, as Exhibit 10.29.)
- 10.16 Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, for services to begin September 1, 2002. (Filed herewith.)
- 10.17 Vectren Corporation Retirement Savings Plan. (Filed and designated in Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15467, as Exhibit 99.1.)
- 10.18 Vectren Corporation Combined Non-Bargaining Retirement Plan. (Filed and designated in Form 10-Q for the quarterly period ended September 30, 2000, File No. 1-15467, as Exhibit 99.2.)
- 10.19 Vectren Corporation Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.32.)
- 10.20 Vectren Corporation Employment Agreement between Vectren Corporation and Niel C. Ellerbrook dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.1.)
- 10.21 Vectren Corporation Employment Agreement between Vectren Corporation and Andrew E. Goebel dated as of March 31, 2000 (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.2.)
- 10.22 Vectren Corporation Employment Agreement between Vectren Corporation and Jerome A. Benkert, Jr. dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.3.)
- 10.23 Vectren Corporation Employment Agreement between Vectren Corporation and Ronald E. Christian dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.5.)
- 10.24 Vectren Corporation Employment Agreement between Vectren Corporation and J. Gordon Hurst dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.7.)
- 10.25 Vectren Corporation Retirement Agreement between Vectren Corporation and J. Gordon Hurst dated as of May 31, 2001. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.41.)
- 10.26 Vectren Corporation Employment Agreement between Vectren Corporation and Richard G. Lynch dated as of March 31, 2000. (Filed and designated in Form 10-Q for the quarterly period ended June 30, 2000, File No. 1-15467, as Exhibit 99.8.)
- 10.27 Vectren Corporation Employment Agreement between Vectren Corporation and William S. Doty dated as

of April 30, 2001. (Filed and designated in Form 10-K for the year ended December 31, 2001, File No. 1-15467, as Exhibit 10.43.)

11. Statement Re Computation Of Per Share Earnings

Not applicable.

12. Statements Re Computation Of Ratios

Not applicable.

13. Annual Report To Security Holders, Form 10-Q Or Quarterly Report To Security Holders

Not applicable.

16. Letter Re Change In Certifying Accountant

Not applicable.

18. Letter Re Change In Accounting Principles

Not applicable.

21. Subsidiaries Of The Company

Not applicable.

22. Published Report Regarding Matters Submitted To Vote Of Security Holders

Not applicable.

23. Consents Of Experts And Counsel

Not applicable.

24. Power Of Attorney

Not applicable.

99. Additional Exhibits

- 99.1 Agreement and Plan of Merger dated as of June 11, 1999 among Indiana Energy, Inc., SIGCORP, Inc. and Vectren Corporation (the "Merger Agreement"). (Filed and designated in Form S-4 to (No. 333-90763) filed on November 12, 1999, File No. 1-15467, as Exhibit 2.)
- 99.2 Amendment No.1 to the Merger Agreement dated December 14, 1999 (Filed and designated in Current Report on Form 8-K filed December 16, 1999, File No. 1-09091, as Exhibit 2.)
- 99.3 Amended and Restated Articles of Incorporation of Vectren Corporation effective March 31, 2000. (Filed and designated in Current Report on Form 8-K filed April 14, 2000, File No. 1-15467, as Exhibit 4.1.)
- 99.4 Amended and Restated Code of By-Laws of Vectren Corporation as of February 26, 2003. (Filed and designated in Form 10-K for the year ended December 31, 2002, File No. 1-15467, as Exhibit 3.2.)

- 99.5 Shareholders Rights Agreement dated as of October 21, 1999 between Vectren Corporation and Equiserve Trust Company, N.A., as Rights Agent. (Filed and designated in Form S-4 (No. 333-90763), filed November 12, 1999, File No. 1-15467, as Exhibit 4.)

Southern Indiana Gas and Electric Company
2002 Form 10-K
Attached Exhibits

The following Exhibits were filed electronically with the SEC with this filing. See Page 52 of this Annual Report on Form 10-K for a complete list of exhibits.

<u>Exhibit</u> <u>Number</u>	<u>Document</u>
3.1	Amended and Restated Articles of Incorporation of Southern Indiana Gas and Electric Company effective January 24, 2003.
3.2	Amended and Restated Code of By-Laws of Southern Indiana Gas and Electric Company as of January 16, 2003.
4.4	Promissory Note for Long-Term Loans dated December 1, 2002, between Southern Indiana Gas and Electric Company and Vectren Utility Holdings, Inc.
10.16	Gas Sales and Portfolio Administration Agreement between Southern Indiana Gas and Electric Company and ProLiance Energy, LLC, for services to begin September 1, 2002.