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, 2003

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 No. 1-2745

Southern Natural Gas Company

(Exact name of registrant as specified in its charter)

Delaware	**63-0196650**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip Code)

Telephone Number: (713) 420-2600

Securities registered pursuant to Section 12(b) of the Act: None

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

State the aggregate market value of the voting stock held by non-affiliates of the registrant: . . . None

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

Common Stock, par value $1 per share. Shares outstanding on March 30, 2004: 1,000

Documents Incorporated by Reference: None

SOUTHERN NATURAL GAS COMPANY

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Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	Dth	= dekatherm
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	Tcfe	= trillion cubic feet equivalent

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", or "ours", we are describing Southern Natural Gas Company, and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation incorporated in 1935. In October 1999, we became a wholly owned subsidiary of El Paso Corporation (El Paso) through the merger of Sonat Inc. with El Paso. Our primary business consists of the interstate transportation and storage of natural gas. We conduct these business activities through our natural gas pipeline system, a liquified natural gas (LNG) receiving terminal, storage facilities, and our 50 percent ownership interest in Citrus Corp. (Citrus), all of which are discussed below.

The Pipeline Systems. The Southern Natural Gas system consists of approximately 8,000 miles of pipeline with a design capacity of approximately 3,296 MMcf/d. During 2003, 2002 and 2001, our average throughput was 2,101 BBtu/d, 2,151 BBtu/d and 2,027 BBtu/d. Our interstate pipeline system extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. We are the principal natural gas supplier to the growing southeastern markets of Alabama and Georgia. Since 2001, the Federal Energy Regulatory Commission (FERC) has approved and we have placed in service our South System I, North System II and the first two phases of our South System II expansions. The final phase of our South System II project, which we anticipate completing by May 2004, will add 138 MMcf/d of capacity along the south mainline of our system in Alabama, Georgia and South Carolina.

We also have a 50 percent ownership interest in Citrus. This interest was contributed to us by El Paso in March 2003. Citrus owns 100 percent of Florida Gas Transmission System, which consists of approximately 4,886 miles of pipeline with a design capacity of 1,980 MMcf/d. During 2003, 2002, and 2001, average throughput was 1,963 BBtu/d, 2,004 BBtu/d and 1,616 BBtu/d. This system extends from South Texas to South Florida. For more information regarding our investment in Citrus and the Florida Gas Transmission System, see Citrus' audited financial statements and related notes beginning on page 53 as well as our Part II, Item 8, Financial Statement and Supplementary Data, Note 15.

LNG Terminal. Our wholly owned subsidiary, Southern LNG Inc., owns an LNG receiving terminal, located on Elba Island, near Savannah, Georgia, capable of achieving a peak sendout of 675 MMcf/d and a base load sendout of 446 MMcf/d. The terminal was placed in service and began receiving deliveries in December 2001. The capacity at the terminal was initially contracted with our affiliate, El Paso Merchant Energy L.P. (EPME), under a contract that extends through 2023. This contract was assigned by EPME to a subsidiary of British Gas, BG LNG Services, LLC in December 2003. In 2003, the FERC approved our plan to expand the peak sendout capacity of the Elba Island Facility by 540 MMcf/d and the base load sendout by 360 MMcf/d (for a total peak sendout capacity once completed of 1,215 MMcf/d and a base load sendout of 806 MMcf/d). The expansion is estimated to cost approximately $159 million and has a planned in-service date of February 2006.

Storage Facilities. Along our pipeline system, we have approximately 60 Bcf of underground working natural gas storage capacity, through our Muldon storage facility in Monroe County, Mississippi, which has a storage capacity of 31 Bcf, and our 50 percent interest in the Bear Creek Storage Company (Bear Creek), with our proportionate share of capacity of 29 Bcf.

Bear Creek is a joint venture that we own equally with our affiliate, Tennessee Storage Company (TSC), a subsidiary of Tennessee Gas Pipeline Company (TGP), also our affiliate. Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to TGP and us under long-term contracts.

Regulatory Environment

Our interstate natural gas transmission system, storage and terminalling operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Our pipeline, LNG terminal and storage facilities operate under FERC-approved tariffs that establish rates, terms and conditions for service to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage and terminalling;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy affiliates;
- terms and conditions of services;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, and include provisions for a reasonable return on our invested capital. Approximately 92 percent of our transportation revenue is attributable to a capacity reservation (demand charge) paid by firm customers. These firm customers are obligated to pay a monthly demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. The remaining 8 percent of our transportation services revenue is attributable to charges based solely on the volumes of natural gas actually transported or stored on our pipeline system. Consequently, our results have historically been relatively stable. However, our results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, competition, regulatory actions and the credit-worthiness of our customers.

Our interstate pipeline system is also subject to federal, state and local statutes and regulations regarding pipeline and LNG plant safety and environmental matters. Our systems have ongoing inspection programs designed to keep all of our facilities in compliance with environmental and pipeline safety requirements. We believe that our systems are in material compliance with the applicable requirements.

We are subject to regulation over the safety requirements in the design, construction, operation and maintenance of our interstate natural gas transmission system and storage facilities by the U.S. Department of Transportation. Our operations on U.S. government land are regulated by the U.S. Department of the Interior and our LNG terminalling business is regulated by the U.S. Coast Guard.

For information regarding Citrus and the Florida Gas Transmission System, see Citrus' audited financial statements and related notes beginning on page 53.

Markets and Competition

We have approximately 270 firm and interruptible customers, including natural gas distribution companies and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies. We provide transportation services in both our natural gas supply and market areas. We have approximately 170 firm transportation contracts with a weighted average remaining contract term of approximately five years. Substantially all of the firm transportation capacity currently available in our two largest market areas is fully subscribed through mid-2005. Our pipeline system connects with multiple pipelines that provide our customers with access to diverse sources of supply and various natural gas markets served by these pipelines.

The following four customers contract for a majority of our firm capacity:

- Atlanta Gas Light Company subscribes to a capacity of 952 MMcf/d under contracts that expire beginning in 2005 through 2007, with the majority expiring in 2005.[1]
- Alabama Gas Corporation subscribes to a capacity of 416 MMcf/d under contracts that expire beginning in 2008.
- Affiliates of Scana Corporation subscribe to a capacity of 246 MMcf/d under contracts that expire beginning in 2005 through 2017.
- Southern Company Services subscribes to a capacity of 409 MMcf/d under contracts that expire beginning in 2010, with the majority expiring in 2018.

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(1) Atlanta Gas Light Company is currently releasing a significant portion of its firm capacity to a subsidiary of Scana Corporation under terms allowed by our tariff.

All of our firm transportation contracts automatically extend the term for additional months or years unless notice of termination is given by one of the parties.

Our interstate natural gas transmission system faces varying degrees of competition from other pipelines, as well as from alternative energy sources such as electricity, hydroelectric power, coal and fuel oil. We compete with other interstate and intrastate pipelines for deliveries to customers who can take deliveries at multiple connection points. We also compete with other pipelines and local distribution companies to deliver increased quantities of natural gas to our market area. In addition, we compete with pipelines and gathering systems for connection to new supply sources.

A number of large natural gas consumers are electric utility companies who use natural gas to fuel electric power generation facilities. Electric power generation is the fastest growing demand sector of the natural gas market. The potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased efficiency in generation and use of surplus electric capacity as a result of open market access.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing the delivery capabilities and operational flexibility, and complementing traditional supply and market areas.

Our existing contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or re-market expiring capacity is dependent on competitive alternatives, access to capital, the regulatory environment at the local, state and federal levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. While we attempt to negotiate contract terms at fully subscribed quantities and at maximum rates allowed under our tariffs, we must, at times, discount our rates to remain competitive.

For information regarding Citrus and the Florida Gas Transmission System, see Citrus' audited financial statements and related notes beginning on page 53.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 10, and is incorporated herein by reference.

Employees

As of March 26, 2004, we had approximately 475 full-time employees, none of whom are subject to a collective bargaining arrangement.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interest in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 10, and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

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

All of our common stock, par value $1 per share, is owned by El Paso and, accordingly, our stock is not publicly traded.

We pay dividends on our common stock from time to time from legally available funds that have been approved for payment by our Board of Directors. In March 2003, in connection with El Paso's contribution of its interest in Citrus to us, we declared and paid a $600 million dividend, $310 million of which was a distribution of outstanding affiliated receivables and $290 million of which was cash. No common stock dividends were declared or paid in 2002 or 2001.

ITEM 6. SELECTED FINANCIAL DATA

The following historical selected financial data should be read together with Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8, Financial Statements and Supplemental Data included in this Form 10-K. These selected historical results are not necessarily indicative of results to be expected in the future.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
	(In millions)				
Operating Results Data:					
Operating revenues	$ 482	$ 429	$ 402	$ 404	$ 417
Operating expenses[1]	206	182	181	198	286
Depreciation, depletion and amortization	47	45	42	33	60
Other income, net	66	64	64	49	47
Non-affiliated interest and debt expense	(87)	(57)	(48)	(38)	(37)
Net income	144	187	145	160	58

	As of December 31,				
	2003	2002	2001	2000	1999
	(In millions)				
Financial Position Data:					
Total assets	$2,830	$2,845	$2,489	$2,157	$2,177
Total long-term debt	1,194	798	699	499	499
Stockholder's equity	1,146	1,603	1,420	1,276	1,194

[1] Charges in 1999 include $90 million of merger-related costs associated with El Paso's merger with Sonat Inc.

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

Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed beginning on page 13.

General

Our business consists of interstate natural gas transmission, storage and terminalling operations. Our interstate natural gas transmission system faces varying degrees of competition from other pipelines, as well as from alternative energy sources, such as hydroelectric power, coal and fuel oil. We are regulated by the FERC, which regulates the rates we can charge our customers. These rates are a function of our costs of providing services to our customers, and include a return on our invested capital. As a result, our financial results have historically been relatively stable. However, they can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the credit-worthiness of our customers. In addition, our ability to extend existing customer contracts or re-market expiring contracted capacity is dependent on competitive alternatives, the regulatory environment and supply and demand factors at the relevant dates these contracts are extended or expire. We make every attempt to negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under our tariffs, although at times, we discount our rates to remain competitive in particular markets.

Results of Operations

Our management, as well as El Paso's management, uses earnings before interest and income taxes (EBIT) to assess the operating results and effectiveness of our business. We define EBIT as net income adjusted for (i) items that do not impact our income from continuing operations, such as the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) affiliated interest income. Our business consists of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense from this measure so that our management can evaluate our operating results without regard to our financing methods. We believe the discussion of our results of operations based on EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated business and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

The following is a reconciliation of our operating income to our EBIT and our EBIT to our net income for the year ended December 31:

	2003	2002	2001
	(In millions, except volume amounts)		
Operating revenues	$ 482	$ 429	$ 402
Operating expenses	(253)	(227)	(223)
Operating income	229	202	179
Earnings from unconsolidated affiliates	55	55	55
Other income	11	9	9
Other	66	64	64
EBIT	295	266	243
Interest and debt expense	(87)	(57)	(48)
Affiliated interest income	4	8	17
Income taxes	(68)	(87)	(67)
Income before cumulative effect of accounting change	144	130	145
Cumulative effect of accounting change, net of income taxes	—	57	—
Net income	$ 144	$ 187	$ 145
Throughput volumes (BBtu/d)[(1)]	3,082	3,153	2,853

[(1)] Throughput volumes include volumes associated with our 50 percent equity interest in Citrus. Prior period volumes have been restated to reflect our current year presentation which includes billable transportation throughput volume for storage injection.

Operating Results (EBIT)

Our EBIT for the year ended December 31, 2003 increased $29 million compared to 2002. During 2003, we placed various phases of our South System I, South System II and North System II mainline expansions into service which, combined, contributed $22 million to the increase in EBIT. Revenues from South System I were higher by $15 million offset by $3 million of operating expenses and a $1 million reduction in equity allowance for funds used during construction (equity AFUDC). Revenues from South System II were higher by $5 million and equity AFUDC was higher by $5 million offset by $2 million in higher operating expenses. Revenues from North System II were $4 million higher offset by $1 million of higher operating expenses. Also contributing to the increase in revenues and EBIT is $14 million from the increase in sales of natural gas volumes that are in excess of our system operating requirements. This increase was primarily due to higher natural gas prices in 2003. These revenues were offset by $3 million of increased electricity expenses at various compressor facilities on our pipeline system. Offsetting the increases in EBIT were higher accruals in 2003 of $3 million pertaining to estimated liabilities to assess and remediate our environmental exposure based on ongoing evaluations at our facilities as well as other changes in our operating revenues and expenses that individually did not have a material impact on EBIT. Also, we have a gas sales agreement that requires us to purchase and sell volumes at a rate close to the market index price. Although the arrangement resulted in variances in both revenue and expense, there was no material effect on EBIT.

Our EBIT for the year ended December 31, 2002 increased $23 million compared to 2001. Our Elba Island LNG facility was placed into service following its recommissioning and began receiving deliveries in December 2001, resulting in $10 million of the increase in EBIT. Revenues from the project increased $32 million offset by $18 million of operating expenses and a $4 million reduction in equity AFUDC. We placed our South System I (Phase I) expansion into service in June 2002, resulting in a $6 million increase in EBIT. This expansion resulted in an $8 million increase in revenues offset by $1 million in operating expenses and a reduction of $1 million in equity AFUDC. Also contributing to the increase in EBIT was a $4 million impact of higher remarketing rates and volumes in 2002 versus 2001 on seasonal turned-back capacity and a $5 million increase in equity AFUDC due primarily to the construction of the South System II and North

System II expansion projects. Other changes in our individual operating revenue and expense items did not have a material impact on EBIT. As discussed above, we have a gas sales agreement that requires us to purchase and sell volumes at a rate close to the market index price. Although the arrangement resulted in variances in both revenue and expense, there was no material effect on EBIT.

Interest and Debt Expense

Interest and debt expense for the year ended December 31, 2003, was $30 million higher than in 2002 primarily due to the issuance in March 2003 of $400 million of 8.875% senior unsecured notes.

Interest and debt expense for the year ended December 31, 2002, was $9 million higher than in 2001. The increase was due to higher average debt balances outstanding in 2002 than in 2001. In February 2002, we issued $300 million aggregate principal amount of 8.0% notes due 2032. This issuance increased interest on long-term debt by approximately $20 million. We also retired $200 million of long-term debt resulting in a decrease to interest expense of approximately $13 million. The remaining increase was primarily due to a February 2001 debt issuance of $300 million that was outstanding for the entire year in 2002.

Affiliated Interest Income

Affiliated interest income for the year ended December 31, 2003, was $4 million lower than in 2002 due to lower average advances to El Paso under its cash management program. The average advance balance for the year ended December 31, 2002 of $445 million decreased to $187 million in 2003. The average short term interest rate increased from 1.9% in 2002 to 2% in 2003.

Affiliated interest income for the year ended December 31, 2002, was $9 million lower than in 2001 due primarily to lower short-term interest rates in 2002, partially offset by increased average advances to El Paso under its cash management program in 2002. The average short-term interest rate decreased from 4.7% in 2001 to 1.9% in 2002 and average advances to El Paso under its cash management program were $445 million in 2002 versus $372 million in 2001.

Income Taxes

	Year Ended December 31,		
	2003	2002	2001
	(In millions, except for rates)		
Income taxes	$68	$87	$67
Effective tax rate	32%	40%	32%

Our effective tax rates were different than the statutory rate of 35 percent for all periods, primarily due to state income taxes and earnings from, and other adjustments attributable to unconsolidated affiliates where we anticipate receiving dividends. For a reconciliation of the statutory rate of 35 percent to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 4.

Other

In the third quarter of 2002, the FERC approved our South System II project and related compressor facilities. This expansion has a design capacity of 330 MMcf/d. Construction will be completed in three phases. Phase I was placed in service in September 2003 and Phase IA was placed in service in November 2003. The targeted in service date for Phase II is May 2004. The South System II project will increase our firm transportation capacity along our south mainline to Alabama, Georgia and South Carolina. Current cost estimates are approximately $242 million, and current expenditures to date as of December 31, 2003 are approximately $195 million.

On May 31, 2002, we filed with the FERC to expand our Elba Island LNG facility for estimated capital costs of $159 million. This expansion will increase the design sendout rate of the facility from 446 MMcf/d to

806 MMcf/d. In April 2003, the FERC approved our expansion. Construction commenced in July 2003 with an in-service date expected to be in February of 2006.

Liquidity and Capital Resources

Liquidity

Our liquidity needs have been provided by cash flows from operating activities and the use of a cash management program with our parent company, El Paso. Under El Paso's cash management program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically provided cash advances to El Paso, and we reflect these net advances to our parent as investing activities in our statement of cash flows. As of December 31, 2003, we had receivables from El Paso of $153 million as a result of this program. These receivables are due upon demand; however, we do not anticipate settlement within the next twelve months. As of December 31, 2003, these receivables were classified as non-current notes receivable from affiliates in our balance sheet. In March 2003, we declared and distributed a dividend of $310 million of our outstanding affiliated receivables to our parent, and we declared and paid a cash dividend of $290 million. As a result of recent announcements by El Paso related to a revision of its estimates of its natural gas and oil reserves, our ability to borrow or recover the amounts advanced under El Paso's cash management program could be impacted. See Item 8, Financial Statements and Supplementary Data, Note 2 for a discussion of these matters. Our cash flows for the years ended December 31 were as follows:

	2003	2002
	(In millions)	
Cash flows from operating activities	$ 167	$ 209
Cash flows from investing activities	(261)	(306)
Cash flows from financing activities	94	97

Cash Flows from Operating Activities

Net cash provided by operating activities were $167 million in 2003 versus $209 million in 2002. This decrease was primarily due to $10 million of customer deposits received in 2002, higher interest payments of $22 million due to increased long-term debt in 2003 and higher tax payments of $10 million in 2003. The remaining decrease is due to the timing of cash payments on accounts receivable and various fluctuations in working capital components.

Cash Flows from Investing Activities

Net cash used in investing activities in 2003 consisted of $237 million in capital expenditures, primarily for our pipeline expansions, and $33 million in affiliated advances. Offsetting this use of cash was $9 million from net proceeds from disposal of assets.

Cash Flows from Financing Activities

Net cash provided by financing activities in 2003 consisted of net proceeds from the issuance of $400 million of long-term debt in March 2003, offset by cash dividends paid of $290 million.

In a series of credit rating agency actions beginning in 2002, and contemporaneously with downgrades of the senior unsecured indebtedness of El Paso, our senior unsecured indebtedness was downgraded to below investment grade and is currently rated B1 by Moody's (with a negative outlook and under review for a possible downgrade) and B− by Standard & Poor's (with a negative outlook). These downgrades will increase our external costs of capital and collateral requirements and could impede our access to capital markets in the future.

Capital Expenditures

Our capital expenditures during the periods indicated are listed below:

	Year Ended December 31,	
	2003	2002
	(In millions)	
Maintenance	$ 54	$ 75
Expansion/Other	183	175
Total	$237	$250

Under our current plan, we expect to spend between approximately $60 million and $70 million in each of the next three years for capital expenditures to maintain the integrity of our pipeline and ensure the reliable delivery of natural gas to our customers. In addition, we have budgeted to spend between $40 million and $120 million in each of the next three years to expand the capacity and services of our system for long-term contracts. We expect to fund our maintenance and expansion capital expenditures through internally generated funds.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2003, for each of the years presented.

	2004	2005	2006	2007	2008	Thereafter	Total
				(In millions)			
Long-term financing obligations[1]	$—	$—	$—	$100	$100	$1,000	$1,200
Operating leases[2]	2	2	1	—	—	—	5
Other contractual commitments and purchase obligations:[3]							
Storage services[4]	18	18	10	—	—	—	46
Commodity purchases[5]	1	2	1	2	1	—	7
Other[6]	45	—	—	—	—	—	45
Total contractual obligations	$66	$22	$12	$102	$101	$1,000	$1,303

(1) See Item 8, Financial Statements and Supplementary Data, Note 9. These amounts reflect our undiscounted obligation.

(2) See Item 8, Financial Statements and Supplementary Data, Note 10. These amounts reflect our undiscounted obligation.

(3) Other contractual commitments and purchase obligations are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and detail approximate timing of these underlying obligations.

(4) These are commitments for firm access to storage capacity owned by our affiliate, Bear Creek.

(5) Includes purchase commitments for natural gas and power.

(6) Includes capital and investment commitments primarily relating to our South System expansions and to the Elba Island facility expansion.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 10, which is incorporated herein by reference.

Critical Accounting Policies

Our critical accounting policies are those accounting policies that require us to make critical accounting estimates in the preparation of our financial statements.

Asset Impairments. The asset impairment accounting rules require us to continually monitor our businesses and the business environment to determine if an event has occurred indicating that a long-lived asset or investment may be impaired. If an event occurs, which is a determination that involves judgment, we then assess the expected future cash flows against which to compare the carrying value of the asset group being evaluated, a process which also involves judgment. We ultimately arrive at the fair value of the asset which is determined through a combination of estimating the proceeds from the sale of the asset, less anticipated selling costs (if we intend to sell the asset), or the discounted estimated cash flows of the asset based on current and anticipated future market conditions (if we intend to hold the asset). The assessment of project level cash flows requires us to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors and these variables can, and often do, differ from our estimates. These changes can have either a positive or negative impact on our impairment estimates. Future changes in the economic and business environment can impact our original and ongoing assessments of potential impairments.

Accounting for Environmental Reserves. We accrue for environmental reserves when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated onsite, offsite and groundwater technical studies, and legal costs. Actual results may differ from our estimates, and our estimates can be, and often are, revised in the future, either negatively or positively, depending upon actual outcomes or changes in expectations based on the facts surrounding each exposure.

As of December 31, 2003, we had accrued approximately $3 million for environmental matters. Our accrual represents the most likely outcome can be reasonably estimated.

Accounting for Postretirement Benefits. Our accruals related to our postretirement benefits are based on actuarial calculations. In performing these calculations, our actuaries must use assumptions, including those related to the return that we expect to earn on our plan assets, discount rates used in calculating benefit obligations, the cost of health care when benefits are provided under our plans and other factors.

Actual results may differ from the assumptions included in these actuarial calculations, and as a result our estimates associated with our postretirement benefits can be, and often are, revised in the future, with either a negative or positive effect on the costs we recognize and the accruals we make. The following table shows the impact of a one percent change in our primary assumptions used in our actuarial calculations associated with our postretirement benefits for the year ended December 31, 2003 (in millions):

	Postretirement Benefits	
	Net Benefit Expense (Income)	Accumulated Postretirement Benefit Obligation
One percent increase in:		
Discount rates	$—	$(10)
Health care cost trends	—	7
One percent decrease in:		
Discount rates	$—	$ 11
Health care cost trends	—	(6)

Our discount rate assumptions reflect the rates of return on the investments we expect to use to settle our postretirement obligations in the future. We combined current and expected rates of return on investment grade corporate bonds to develop the discount rates used in our benefit expense and obligation estimates as of September 30, 2003.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2003, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Based on our assessment of those standards, we do not believe there are any that could have a material impact on us.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate," and similar expressions will generally identify forward-looking statements. Our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Securities and Exchange Commission (SEC) from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

Risks Related to Our Business

Our success depends on factors beyond our control.

Our business is the transportation and storage of natural gas for third parties. As a result, the volume of natural gas involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current transmission and storage volumes and rates, to renegotiate existing contracts as they expire, or to remarket unsubscribed capacity:

- future weather conditions, including those that favor alternative energy sources such as hydroelectric power;
- price competition;
- drilling activity and supply availability of natural gas;
- expiration and/or turn back of significant contracts;
- service area competition;
- changes in regulation and actions of regulatory bodies;
- credit risk of our customer base;
- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions; and
- unfavorable movements in natural gas and liquids prices.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Our revenues are generated under transportation contracts which expire periodically and must be renegotiated and extended or replaced. Although we actively pursue the renegotiation, extension and/or replacement of these contracts, we cannot assure you that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. Currently, our firm transportation capacity is fully subscribed through mid-2005 in our largest market areas, but could be renegotiated at rates below current rates upon the expiration of these contracts. For a further discussion of these matters, see Part I, Business — Markets and Competition.

In particular, our ability to extend and/or replace transportation contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by us;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

Fluctuations in energy commodity prices could adversely affect our business.

Revenues generated by our contracts depend on volumes and rates, both of which can be affected by the prices of natural gas. Increased natural gas prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas fired power plants. Increased prices could also result in industrial plant shutdowns or load losses to competitive fuels and local distribution companies' loss of customer base. The success of our operations is subject to continued development of additional oil and natural gas reserves in the vicinity of our facilities and our ability to access additional suppliers from interconnecting pipelines, primarily in the Gulf of Mexico, to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission or storage on our system. If natural gas prices in the supply basins connected to our pipeline systems are higher on a delivered basis to our off-system markets than delivered prices from other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the transportation of natural gas;
- abundance of supplies of alternative energy sources; and
- political unrest among oil-producing countries.

The agencies that regulate us and our customers affect our profitability.

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Our LNG terminalling business is also regulated by the U.S. Coast Guard. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates we are permitted to charge our customers for our services. If our tariff rates were reduced in a future rate proceeding, if our volume of business under our currently permitted rates was decreased significantly or if we were required to substantially discount the rates for our services because of competition, our profitability and liquidity could be reduced.

Further, state agencies and local governments that regulate our local distribution company customers could impose requirements that could impact demand for our services.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- the possible introduction of future environmental laws and regulations.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties, and these amounts could be material. For additional information, see Item 8, Financial Statements and Supplementary Data, Note 10.

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

Four customers contract for a majority of our firm transportation capacity.

For 2003, contracts with Atlanta Gas Light Company, Southern Company Services, Alabama Gas Corporation and Scana Corporation represented approximately 30%, 13%, 13% and 8% of our firm transportation capacity. For additional information, see Part I, Item 1, Business — Markets and Competition and Part II, Item 8, Financial Statements and Supplementary Data, Note 13. The loss of one of these customers or a decline in its credit-worthiness could adversely affect our results of operations, financial position and cash flow.

Risks Related to Our Affiliation with El Paso

El Paso files reports, proxy statements and other information with the SEC under the Securities Exchange Act of 1934, as amended. Each prospective investor should consider this information and the matters disclosed therein in addition to the matters described in this report. Such information is not incorporated by reference herein.

Our relationship with El Paso and its financial condition subjects us to potential risks that are beyond our control.

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The senior unsecured indebtedness of El Paso has been downgraded to below investment grade, currently rated Caa1 by Moody's (with a negative outlook and under review for a possible downgrade) and CCC+ by Standard & Poor's (with a negative outlook). Our senior unsecured indebtedness is currently rated B1 by Moody's (with a negative outlook and under review for a possible downgrade) and B− by Standard & Poor's (with a negative outlook). These downgrades will increase our cost of capital and collateral requirements, and could impede our access to capital markets. As a result of these downgrades, El Paso has realized substantial demands on its liquidity. These downgrades are a result, at least in part, of the outlook generally for the consolidated businesses of El Paso and its needs for liquidity.

El Paso has embarked on its 2003 Long-Range Plan that, among other things, defines El Paso's future businesses, targets significant debt reduction and establishes financial goals. An inability to meet these objectives could adversely affect El Paso's liquidity position, and in turn affect our financial condition.

Pursuant to El Paso's cash management program, surplus cash is made available to El Paso in exchange for an affiliated receivable. In addition, we conduct commercial transactions with some of our affiliates. As of December 31, 2003, we have net receivables of approximately $145 million from El Paso and its affiliates. El Paso provides cash management and other corporate services for us. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program, or that our affiliates would pay their obligations to us. However, we might still be required to satisfy affiliated company payables. Our inability to recover any intercompany receivables owed to us could adversely affect our ability to repay our outstanding indebtedness. For a further discussion of these matters, see Item 8, Financial Statements and Supplementary Data, Note 15.

Furthermore, in February 2004, El Paso announced that it had completed a review of its estimates of natural gas and oil reserves. As a result of this review, El Paso announced that it was reducing its proved natural gas and oil reserves by approximately 1.8 Tcfe. El Paso also announced that this reserve revision would result in a 2003 charge of approximately $1 billion if the full impact of the revision was taken in that period. In March 2004, El Paso provided an update and stated that the revisions would likely result in a restatement of its historical financial statements, the timing and magnitude of which are still being determined. El Paso has retained a law firm to conduct an internal investigation, which is ongoing. Also, as a result of the reduction in reserve estimates, several class action suits have been filed against El Paso and several of its subsidiaries, but not against us. The reduction in reserve estimates may also become the subject of an SEC investigation or separate inquiries by other governmental regulatory agencies. These investigations and lawsuits may further negatively impact El Paso's credit ratings and place further demands on its liquidity. See Item 8, Financial Statements and Supplementary Data, Note 2 for a further discussion of the possible impacts of this announcement.

Our subsidiary may be subject to a change of control under certain circumstances.

Our ownership in Bear Creek is pledged as collateral under El Paso's revolving $3 billion credit facility and approximately $1 billion of other financing arrangements, including leases, letter's of credit and other facilities. As a result, Bear Creek's ownership is subject to change if El Paso's lenders under these facilities exercise rights over their collateral.

We could be substantively consolidated with El Paso if El Paso were forced to seek protection from its creditors in bankruptcy.

If El Paso were the subject of voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. The equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities and to consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. We believe that any effort to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, we cannot assure you that El Paso and/or its other subsidiaries or their respective creditors would not attempt to advance such claims in a bankruptcy proceeding or, if advanced, how a bankruptcy court would resolve the issue. If a bankruptcy court were to substantively consolidate us with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and liquidity.

We are a wholly owned subsidiary of El Paso.

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

Risks Related to Citrus Corp.

Florida Gas Transmission Company (FGT) depends substantially upon a small number of customers.

Upon completion of its current expansion, the five most significant customers on FGT's pipeline system will account for approximately 74% of contracted capacity, with the two most significant customers, Florida Power & Light Company, or FP&L, and TECO Energy, Inc., including its subsidiaries Tampa Electric Company and Peoples Gas System, Inc., being obligated for approximately 39% and 21% of such capacity. Accordingly, failure of one or more of FGT's most significant customers to pay reservation charges could reduce its revenues materially and have a material adverse effect on its business, financial condition and results of operations.

Important actions by Citrus and FGT require approval by both Enron Corp. (Enron) and us.

El Paso contributed its 50 percent interest in Citrus to us. Enron owns the other 50 percent interest. Citrus' organizational documents and FGT's organizational documents require that "important matters" be approved by both Enron and us. Important matters include the declaration of dividends and similar payments, the approval of operating budgets, the incurrence of indebtedness and the consummation of significant transactions. Consequently, we are dependent on Enron's agreement to effect any, such actions. Enron's interests with respect to these important matters could be different from ours and, accordingly, we may be unable to cause Citrus and FGT to take important actions, such as the payment of dividends and the sale or acquisition of assets.

Citrus depends on Enron entities to provide it with management and support services under an informal administrative services arrangement.

Various Enron entities provide management and support services to Citrus and its subsidiaries, pursuant to an informal administrative services arrangement. These services include administration, legal, compliance and emergency services. The arrangement was originally governed by the provisions of an operating agreement between an Enron affiliate and Citrus. The term of the operating agreement expired on June 30, 2001 and has not been extended. However, the Enron entities have continued to provide their services under an informal arrangement based on the provisions of the original operating agreement. Under the arrangement, Citrus and its subsidiaries reimburse the Enron entities for costs attributable to the operations of Citrus and its subsidiaries.

Although we believe that the Enron entities will continue to perform management and support services for Citrus and its subsidiaries, and that Citrus could obtain such services from other sources in a timely and cost effective manner, Citrus may be unable to obtain such services from other sources on terms favorable to Citrus in the event the Enron entities stop providing them. Failure to obtain management and support services in a timely and cost effective manner could have a material adverse effect on Citrus' business.

The blanket market authority of one of Citrus' subsidiaries may be terminated.

On March 26, 2003, the FERC issued an order directing Citrus Trading Corporation (CTC), a direct subsidiary of Citrus, to show cause, in a proceeding initiated by the order, why the FERC should not terminate CTC's blanket marketing certificates by which CTC is authorized to make sales for resale at negotiated rates in interstate commerce of natural gas subject to the Natural Gas Act of 1938.

Ongoing litigation regarding CTC could adversely affect our business.

In March 2003, CTC filed suit against Duke Energy LNG Sales, Inc. (Duke) seeking damages for breach of a gas supply contract under which CTC was entitled to purchase regasified liquefied natural gas. In April 2003, Duke forwarded a letter to CTC purporting to terminate the contract due to the alleged failure of CTC to increase the amount of an outstanding letter of credit backstopping its purchase obligations. On May 1, 2003, CTC notified Duke that Duke was in default under the contract. CTC subsequently filed an amended complaint, alleging wrongful contract termination and specifying damages of $185 million. At this time, the outcome of this litigation is not determinable. For further discussion of these matters, see Item 8, Financial Statements and Supplementary Data, Note 10.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk is exposure to changing interest rates. The table below shows the carrying value and related weighted average effective interest rates of our interest bearing securities, by expected maturity dates, and the fair value of those securities. As of December 31, 2003, the fair values of our fixed rate long-term debt securities have been estimated based on quoted market prices for the same or similar issues.

	December 31, 2003					December 31, 2002	
	Expected Fiscal Year of Maturity of Carrying Amounts						
	2007	2008	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
				(In millions)			
Liabilities:							
Long-term debt, including current portion — fixed rate	$100	$100	$994	$1,194	$1,259	$798	$696
Average interest rate	6.8%	6.3%	8.3%				

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2003	2002	2001
Operating revenues	$482	$429	$402
Operating expenses			
Operation and maintenance	185	162	162
Depreciation, depletion and amortization	47	45	42
Taxes, other than income taxes	21	20	19
	253	227	223
Operating income	229	202	179
Earnings from unconsolidated affiliates	55	55	55
Other income	11	9	9
Interest and debt expense	(87)	(57)	(48)
Affiliated interest income	4	8	17
Income before income taxes	212	217	212
Income taxes	68	87	67
Income before cumulative effect of accounting change	144	130	145
Cumulative effect of accounting change, net of income tax	—	57	—
Net income	$144	$187	$145

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ —	$ —
Accounts and notes receivable		
Customer, net of allowance of $3 in 2003 and 2002	83	71
Affiliates	—	61
Other	1	3
Materials and supplies	12	14
Other	12	10
Total current assets	108	159
Property, plant and equipment, at cost	3,055	2,846
Less accumulated depreciation, depletion and amortization	1,326	1,304
Total property, plant and equipment, net	1,729	1,542
Other assets		
Investments in unconsolidated affiliates	788	734
Note receivable from affiliate	153	369
Regulatory assets	35	34
Other	17	7
	993	1,144
Total assets	$2,830	$2,845
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 34	$ 36
Affiliates	8	9
Other	1	1
Taxes payable	59	49
Accrued interest	30	20
Deposits on transportation contracts	13	13
Other	5	4
Total current liabilities	150	132
Long-term debt, less current maturities	1,194	798
Other liabilities		
Deferred income taxes	286	260
Other	54	52
	340	312
Commitments and contingencies		
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	340	341
Retained earnings	814	1,270
Accumulated other comprehensive loss	(8)	(8)
Total stockholder's equity	1,146	1,603
Total liabilities and stockholder's equity	$2,830	$2,845

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2003	2002	2001
Cash flows from operating activities			
Net income	$ 144	$ 187	$ 145
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	47	45	42
Deferred income tax expense	31	64	60
Net gain on the sale of assets	—	—	(1)
Undistributed earnings of unconsolidated affiliates	(54)	(55)	(55)
Cumulative effect of accounting change	—	(57)	—
Other non-cash income items	—	3	(7)
Current asset and liability changes, net of non-cash transactions			
Accounts and notes receivable	(10)	(1)	10
Accounts payable	(4)	—	(4)
Taxes payable	11	(2)	(49)
Other current asset and liability changes			
Assets	(5)	13	(26)
Liabilities	10	6	—
Non-current asset and liability changes			
Assets	(3)	8	18
Liabilities	—	(2)	(21)
Net cash provided by operating activities	167	209	112
Cash flows from investing activities			
Additions to property, plant and equipment	(237)	(250)	(167)
Net proceeds on disposal of assets	9	4	9
Net change in affiliated advances receivable	(33)	(59)	(163)
Other	—	(1)	12
Net cash used in investing activities	(261)	(306)	(309)
Cash flows from financing activities			
Payments to retire long-term debt	—	(200)	(100)
Net proceeds from the issuance of long-term debt	384	297	297
Dividends paid	(290)	—	—
Net cash provided by financing activities	94	97	197
Change in cash and cash equivalents	—	—	—
Cash and cash equivalents			
Beginning of period	—	—	—
End of period	$ —	$ —	$ —

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In millions, except share amounts)

	Common stock		Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Total stockholder's equity
	Shares	Amount				
January 1, 2001	1,000	$ —	$ 337	$ 938	$ —	$1,275
Net income				145		145
Allocated tax benefit of El Paso equity plans			3			3
Other comprehensive loss					(3)	(3)
December 31, 2001	1,000	—	340	1,083	(3)	1,420
Net income				187		187
Allocated tax benefit of El Paso equity plans			1			1
Other comprehensive loss					(5)	(5)
December 31, 2002	1,000	—	341	1,270	(8)	1,603
Net income				144		144
Allocated tax expense of El Paso equity plans			(1)			(1)
Dividends				(600)		(600)
December 31, 2003	1,000	$ —	$ 340	$ 814	$ (8)	$1,146

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2003	**2002**	**2001**
Net income	$144	$187	$145
Net losses from cash flow hedging activities:			
Unrealized mark-to-market losses arising during period (net of income tax of $1 in 2002 and 2001)	—	(5)	(3)
Other comprehensive loss	—	(5)	(3)
Comprehensive income	$144	$182	$142

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholder's equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Regulated Operations

Our natural gas systems and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we currently apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* We perform an annual study to assess the ongoing applicability of SFAS No. 71. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include capitalizing an equity return component on regulated capital projects, post retirement employee benefit plans, and other costs included in, or expected to be included in, future rates.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of an outstanding receivable balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Materials and Supplies

We value materials and supplies at the lower of cost or market value with cost determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances generally occur when the actual amount of natural gas received on a customer's contract at the supply point differs from the actual amount of natural gas delivered under the customer's transportation contract at the delivery point. We value imbalances due to or from shippers at specified index prices set forth in our tariff based on the production month in which the imbalances occur. Customer imbalances are aggregated and netted (by customer) on a monthly basis, and settled in cash, subject to the terms of our tariff. For differences in value between the amounts we pay or receive for the purchase or sale of gas used to resolve shipper imbalances over the course of a year, we have the right under our tariff to recover applicable losses through a storage cost reconciliation charge. This charge is applied to all volumes transported on our system. We are obligated annually to true-up any losses or gains obtained during the course of each year in calculating the following years' storage cost reconciliation charge.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to affiliates. In addition, we classify all imbalances as current.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. We capitalize direct costs, such as labor and materials and indirect costs, such as overhead, interest and an equity return component for our regulated businesses as allowed by the FERC. We capitalize the major units of property replacements or improvements and expense minor items.

We use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the FERC-accepted depreciation rate to the total cost of the group until its net book value equals its salvage value. Currently, our depreciation rates vary from one to 20 percent. Using these rates, the remaining depreciable lives of these assets range from two to 57 years. We re-evaluate depreciation rates each time we file with the FERC for a change in our transportation and storage service rates.

When we retire regulated property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost to remove, sell or dispose, less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income. On non-regulated property, plant and equipment, we record a gain or loss in income for the difference between the net book value relative to the proceeds received, if any, when the asset is sold or retired.

At December 31, 2003 and 2002, we had approximately $81 million and $126 million of construction work in progress included in our property, plant and equipment.

As a FERC-regulated company, we capitalize a carrying cost (an allowance for funds used during construction or AFUDC) on funds invested in our construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on our average cost of debt. Debt amounts capitalized during the years ended December 31, 2003, 2002 and 2001, were $3 million, $2 million and $2 million. These amounts are included as an offset to interest expense in our income statement. The equity portion is calculated using the most recent FERC approved equity rate of return. The equity amounts capitalized during the years ended December 31, 2003, 2002 and 2001 were $7 million, $5 million and $5 million (exclusive of any tax related impacts). These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity financed construction are reflected as an increase in the cost of the asset on our balance sheet.

Asset Impairments

We evaluate our assets for impairment when events or circumstances indicate that a long-lived asset's carrying value may not be recovered. These events include market declines, changes in the manner in which we intend to use an asset or decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. At the time we decide to exit an activity or sell a long-lived asset or group of assets, we adjust the carrying value of those assets downward, if necessary, to the estimated sales price, less costs to sell. We also classify these assets as either held for sale or as discontinued operations, depending on whether they have independently determinable cash flows.

Revenue Recognition

Our revenues are generated from transportation and storage services and sales under natural gas sales contracts. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period. For interruptible or volumetric based transportation services, as well as revenues on sales of natural gas and related products, we record revenues when physical deliveries of natural gas and other commodities are made at the agreed upon delivery point. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. We are subject to FERC regulations and, as a result, a portion of revenues we collect may possibly be refunded in a final order of a pending rate proceeding or as a result of a rate settlement.

Price Risk Management Activities

Our equity investee, Citrus, uses derivatives to mitigate, or hedge, cash flow risk associated with its variable interest rates on long-term debt. Citrus accounts for these derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and records changes in the fair value of these derivatives in other comprehensive income. We reflect our proportionate share of the impact these derivative instruments have on Citrus' financial statements as adjustments to our other comprehensive income and our investment in unconsolidated affiliates.

Environmental Costs and Other Contingencies

We record environmental liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when the clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal and regulatory guidelines dictate otherwise. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into account the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage, rate recovery, government sponsored and other programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Income Taxes

We report current income taxes based on our taxable income and we provide for deferred income taxes to reflect estimated future tax payments or receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

El Paso maintains a tax accrual policy to record both regular and alternative minimum taxes for companies included in its consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. El Paso pays all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso may bill or refund its subsidiaries for their portion of these income tax payments.

2. Liquidity

In February 2004, El Paso announced that it had completed a review of its estimates of its natural gas and oil reserves. As a result of this review, El Paso announced that it was reducing its proved natural gas and oil reserves by approximately 1.8 Tcfe. El Paso also announced that this reserve revision would result in a 2003 charge of approximately $1 billion if the full impact of the revision was taken in that period. In March 2004, El Paso provided an update and stated that the revision would likely result in a restatement of its historical financial statements, the timing and magnitude of which are still being determined.

A material restatement of El Paso's prior period financial statements would result in an "event of default" under El Paso's revolving credit facility and various other financing transactions; specifically under the provisions of the facility related to representations and warranties on the accuracy of its historical financial statements and its debt to total capitalization ratio. El Paso has received waivers on its revolving credit facility and other financing transactions that were required to address potential issues related to its recently announced reserve revisions. Based upon a review of the covenants and indentures of our outstanding indebtedness, we do not believe that a default on El Paso's revolving credit facility would constitute an event of default on our debt securities.

El Paso is a significant potential source of liquidity to us. We participate in El Paso's cash management program. Under this program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically and consistently provided cash to El Paso under this program, and as of December 31, 2003, we had a cash advance receivable from El Paso of $153 million, classified as a non-current asset in our balance sheet. If El Paso were unable to meet its liquidity needs, we would not have access to this source of liquidity and there is no assurance that El Paso could repay the entire amounts owed to us. In that event, we could be required to write-off some amount of these advances, which could have a material impact on our stockholder's equity. Furthermore, we would still be required to repay affiliated company payables. Non-cash write-downs that cause our debt to EBITDA (as defined in our indentures) ratio to fall below 6 to 1 could prohibit us from incurring additional debt. However, this non-cash equity reduction would not result in an event of default under our existing debt securities.

Our equity investment in Bear Creek serves as collateral under El Paso's revolving credit facility and other of El Paso's borrowings. If El Paso's lenders under this facility or those other borrowings were to exercise their rights to this collateral, our investment could be liquidated. However, this liquidation would not constitute an event of default under our existing debt securities.

If, as a result of the events described above, El Paso were subject to voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. We believe that claims to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, there is no assurance that El Paso and/or its other subsidiaries or their creditors would not advance such a claim in a bankruptcy proceeding. If we were to be substantively consolidated in a bankruptcy proceeding with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and our liquidity.

Finally, we have cross-acceleration provisions in our long-term debt that state that should we incur an event of default under which borrowings in excess of $10 million are accelerated, our long-term debt could also be accelerated. The acceleration of our long-term debt would adversely affect our liquidity position and, in turn, our financial condition.

3. Investment in Citrus

In March 2003, El Paso contributed to us all of its 50 percent ownership interest in Citrus, a Delaware corporation with a net book value at the time of contribution of approximately $578 million. Since both the investment in Citrus, which is accounted for as an equity investment, and our common stock were owned by El Paso at the time of the contribution, we were required to reflect the investment in Citrus at its historical cost and include it in our financial statements for all periods presented. As a result, our financial statements reflect the contribution of Citrus as though it occurred on January 1, 2001.

4. Income Taxes

The following table reflects the components of income tax expense included in income before cumulative effect of accounting change for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Current			
Federal	$31	$20	$ 9
State	6	3	(2)
	37	23	7
Deferred			
Federal	28	61	53
State	3	3	7
	31	64	60
Total income tax expense	$68	$87	$67

Our income tax expense included in income before cumulative effect of accounting change differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Income tax expense at the statutory federal rate of 35%	$ 74	$76	$ 74
Items creating rate differences:			
State income tax, net of federal income tax benefit	6	4	3
Earnings from, and other adjustments attributable to, unconsolidated affiliates where we anticipate receiving dividends	(12)	7	(12)
Other	—	—	2
Income tax expense	$ 68	$87	$ 67
Effective tax rate	32%	40%	32%

The following are the components of our net deferred tax liability as of December 31:

	2003	2002
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$255	$217
Regulatory assets	10	21
Investment in unconsolidated affiliates	43	40
Materials and supplies	11	11
Other	23	25
Total deferred tax liability	342	314
Deferred tax assets		
Accrual for regulatory issues	24	31
Employee benefit and deferred compensation obligations	11	18
U.S. net operating loss and tax credit carryovers	7	7
Other	17	7
Valuation allowance	(1)	(1)
Total deferred tax asset	58	62
Net deferred tax liability	$284	$252

Under El Paso's tax accrual policy, we are allocated the tax effects associated with our employees' non-qualified dispositions of employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock as well as restricted stock dividends. This allocation increased taxes payable by $1 million in 2003 and reduced taxes payable by $1 million in 2002 and $3 million in 2001. These tax effects are included in additional paid-in capital in our balance sheet.

The following are the components of our carryovers as of December 31, 2003:

Carryover	Amount	Expiration Date
	(In millions)	
General business credit	$ 1	2009-2017
Net operating loss[1]	16	2018-2021

(1) $14 million of this amount expires in 2018, $1 million in 2019 and $1 million in 2021.

Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations. We have recorded a valuation allowance to reserve for the deferred taxes related to our general business credits.

5. Cumulative Effect of Accounting Change

On January 1, 2002, we adopted SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets.* SFAS No. 141 requires that once SFAS No. 142 is adopted, negative goodwill should be written off as a cumulative effect of an accounting change. In March 2003, El Paso contributed its investment in Citrus to us. See Note 3 for a discussion of the accounting treatment for this transaction. As a result of our ownership in Citrus, which had negative goodwill associated with El Paso's original investment, we recorded a pre-tax and after-tax gain of $57 million as a cumulative effect of an accounting change in our 2002 income statement to reflect the adoption of SFAS No. 141 and SFAS No. 142.

6. Financial Instruments

The carrying amounts and estimated fair values of our financial instruments are as follows at December 31:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Balance sheet financial instruments:				
Long-term debt, including current maturities[1]	$1,194	$1,259	$798	$696

[1] We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

As of December 31, 2003 and 2002, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term maturity of these instruments.

7. Regulatory Assets and Liabilities

Our regulatory assets and regulatory liabilities as of December 31, 2003 and 2002 are presented below. These balances are presented in our balance sheets on a gross basis.

Description	December 31, 2003	December 31, 2002	Remaining Recovery Period
	(in millions)		
Non-current regulatory assets			
Grossed-up deferred taxes on capitalized funds used during construction	$35	$32	[2]
Other	—	2	5-9 years
Total non-current regulatory assets[1]	$35	$34	
Non-current regulatory liabilities			
Cost of removal of offshore assets	$17	$15	N/A
Excess deferred federal income taxes	2	2	N/A
Total non-current regulatory liabilities[3]	$19	$17	

[1] These amounts are not included in our rate base on which we earn a current return.

[2] Amounts are recovered over the remaining depreciable lives of property, plant and equipment.

[3] Amounts are included as other non-current liabilities in our balance sheet.

8. Accounting for Hedging Activities

As of December 31, 2003 and 2002, our equity interest in the value of Citrus' cash flow hedges included in accumulated other comprehensive loss was an unrealized loss of $8 million, net of income taxes. This amount will be reclassified to earnings over the terms of Citrus' outstanding debt. We estimate that less than $1 million of this unrealized loss will be reclassified from accumulated other comprehensive loss over the next twelve months. For the years ended December 31, 2003, 2002 and 2001, no ineffectiveness was recorded in earnings on these cash flow hedges.

9. Long-Term Debt

Our long-term debt outstanding consisted of the following at December 31:

	2003	2002
	(In millions)	
6.70% Notes due 2007	$ 100	$100
6.125% Notes due 2008	100	100
8.875% Notes due 2010	400	—
7.35% Notes due 2031	300	300
8.0% Notes due 2032	300	300
	1,200	800
Less: Unamortized discount	6	2
Long-term debt, less current maturities	$1,194	$798

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

Year	(In millions)
2007	$ 100
2008	100
Thereafter	1,000
Total maturities of long-term debt	$1,200

Our long-term debt contains cross-acceleration provisions, the most restrictive of which is a $10 million cross-acceleration clause. If triggered, repayment of our long-term debt, could be accelerated. In addition, under our indentures, we are subject to a number of restrictions and covenants. The most restrictive of these include (i) limitations on the incurrence of additional debt, based on a ratio of debt to EBITDA (as defined in the agreements); (ii) limitations, in some cases, on transactions with our affiliates; (iii) limitations on the incurrence of liens; (iv) potential limitations on our ability to declare and pay dividends; and (v) potential limitations on our ability to participate in the El Paso cash management program. For the year ended December 31, 2003, we were in compliance with these covenants.

In March 2003, we issued $400 million of unsecured senior notes with an annual interest rate of 8.875%. The notes mature in 2010. Net proceeds were used to pay a cash dividend to our parent of approximately $290 million, while the remaining proceeds were used for capital expenditures in 2003.

In January 2002, we repaid $100 million of our 7.85% notes due 2002. In February 2002, we issued $300 million aggregate principal amount of 8.0% notes, due 2032. Proceeds were approximately $297 million, net of issuance costs. In May 2002, we repaid $100 million of our 8.625% notes due 2002.

Other Financing Arrangements

In April 2003, El Paso entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. El Paso's $1 billion revolving credit facility, which matured in August 2003, and approximately $1 billion of other El Paso financing arrangements (including leases, letters of credit and other facilities) were also amended to conform El Paso's obligations under those arrangements to the $3 billion revolving credit facility. We are not a borrower under El Paso's $3 billion revolving credit facility; however, El Paso's equity in several of its subsidiaries, including our equity in Bear Creek, collateralizes the credit facility and the other financing arrangements. See Note 2 for a discussion regarding El Paso's possible default on the $3 billion revolving credit facility.

10. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, we and a number of our affiliates were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Key. We were named as a defendant in *Randall Key v. LDI Contractors, Inc., et al.,* filed in 2002 in the Circuit Court of Jefferson County, Alabama. The plaintiff, an employee of a contractor, suffered paralysis as a result of a coupling failure during a pipeline repressurization in May 2002. The plaintiff is seeking compensatory and punitive damages against us and two other defendants. We are pursuing contribution and indemnity from the codefendants and their insurers. The matter is set for trial in October 2004. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Royalty Claim. In five contract settlements reached in the late 1980s with Elf Aquitaine (Elf) pertaining to the pricing of gas produced from certain federal offshore blocks, we indemnified Elf against royalty claims that potentially could have been asserted by the Minerals Management Service (MMS). Following its settlements with us, Elf received demands from MMS for royalty payments related to the settlements. With our approval, Elf protested the demands for over a decade while trying to reach a settlement with the MMS. Elf, which is now Total E&P USA (Total), has recently advised us that it is now renewing efforts to settle claims by the MMS for excess royalties attributable to price reductions that we achieved in the gas contract settlements in the late 1980s. Total has informed us that the MMS is claiming $10.2 million in royalties, including $7.3 million of interest, for the five settlements with us and that Total is proposing to make a settlement offer to MMS. If Total cannot resolve these claims administratively with MMS, then an appeal can be taken to the federal courts. We have the right under a pre-existing settlement with our customers to recover through a surcharge payable by our customers a portion of the amount ultimately paid to MMS under the royalty indemnity with Total.

In addition to the above matters, we are also a named defendant in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate. As of December 31, 2003, we had accrued $1 million for our outstanding legal matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2003, we had accrued approximately $3 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, which we anticipate incurring through 2027. Our accrual was based on the most likely outcome that can be reasonably estimated. Below is a reconciliation of our environmental remediation liabilities as of December 31, 2003 (in millions):

Balance as of January 1, 2003	$ 4
Additions/Adjustments for remediation activities	3
Payments for remediation activities	(4)
Balance as of December 31, 2003	$ 3

In addition, we expect to make capital expenditures for environmental matters of approximately $7 million in the aggregate for the years 2004 through 2008. These expenditures primarily relate to compliance with clean air regulations. For 2004, we estimate that our total remediation expenditures will be approximately $3 million, which primarily will be expended under government directed clean-up plans.

Toca Air Permit Violation. In June 2003, we notified the Louisiana Department of Environmental Quality (LDEQ) that we had discovered possible compliance issues with respect to operations at our Toca Compressor Station. In response to a request from the LDEQ, we submitted a report in September 2003 documenting that there had been unpermitted emissions from nine condensate storage tanks and a tank truck loading station. In December 2003, the LDEQ issued an order requiring us to correct the existing operating permit and achieve compliance with federal and state laws and regulations. Our Toca Compressor Station will invest an estimated $6 million to upgrade the station's environmental controls by 2005. We filed a revised permit application and a plan for compliance with the LDEQ in January 2004. The LDEQ has not indicated what, if any, penalty amount it will assess for this matter.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Rates and Regulatory Matters

There are several regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

While the outcome of our outstanding rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure and accruals related to these matters.

Other Matters

Enron Bankruptcy. In December 2001, Enron and a number of its subsidiaries, including Enron North America Corp. (ENA), filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with ENA for, among other things, the transportation of natural gas. Following the rejection of these contracts by ENA, we filed a proof of claim totaling $1.9 million with the Bankruptcy Court. We have fully reserved for the amounts due from ENA.

In addition, we own 50 percent of the outstanding stock of Citrus with Enron. El Paso and Enron are parties to a Capital Stock Agreement that governs, among other things, the ownership of capital stock in Citrus. The Capital Stock Agreement contains restrictions on the transferability of the capital stock of Citrus. These restrictions include rights of first refusal if either owner desires to sell its interest in Citrus. Those shares must first be offered to the other stockholder before the shares can be sold or transferred to a party other than a wholly-owned subsidiary.

On October 31, 2003, Enron filed a motion with the Bankruptcy Court seeking approval to assign the Capital Stock Agreement to CrossCountry Energy Corp., a newly created subsidiary which would acquire Enron's stock in Citrus and then be distributed to Enron's creditors. We objected to the motion on the basis that (1) we must consent to the assignment and (2) the assignment would effectively circumvent the transferability restrictions under the Capital Stock Agreement, including our right of first refusal. The Bankruptcy Court granted the motion on December 1, 2003.

Duke. On March 7, 2003, CTC, a direct subsidiary of Citrus, filed suit against Duke Energy LNG Sales, Inc. titled *Citrus Trading Corp. v. Duke Energy LNG Sales, Inc.* in the District Court of Harris County, Texas seeking damages for breach of a gas supply contract.

In April 2003, Duke: (i) sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit backstopping its purchase obligations; (ii) filed an answer to CTC's complaint stating among other reasons that CTC had triggered the early termination and breached the gas supply contract; and (iii) removed the case to federal court, based on the existence of foreign arbitration with its LNG supplier, Sonatrading Amsterdam B.V. Sonatrading was alleged to have repudiated its supply contract with Duke.

In May 2003, CTC: (i) notified Duke that it was in default under the gas supply contract, demanding cover damages for alternate supplies obtained by CTC; and (ii) filed a motion to remand the case back to state court. Subsequently, CTC gave Duke notice of early termination of the gas supply contract.

In August 2003, Duke filed a third-party petition against Sonatrading. In October 2003, CTC filed an amended complaint, alleging wrongful contract termination and specifying damages of $185 million. Also in October 2003, Duke filed various petitions claiming that Sonatrading's breach of contract results in its being responsible for any damages the court may ultimately find Duke owes to Citrus. In October 2003, the case was once again removed to federal court. In November 2003, pursuant to a judicial order, CTC filed an amended complaint against Duke. We do not expect the ultimate resolution of this matter to have a material adverse effect on us.

While the outcome of these matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters, and adjust our accruals accordingly. The impact of these changes may have a material effect on our results of operations, our financial position, and our cash flows in the periods these events occur.

Capital Commitments and Purchase Obligations

At December 31, 2003, we had capital and investment commitments of $45 million primarily relating to our South System expansion and to the Elba Island facility expansion. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. We have entered into unconditional purchase obligations for products and services totaling $51 million at December 31, 2003. Our annual obligations under these agreements are $19 million for each of the years 2004 through 2005, $11 million for 2006, $1 million for 2007 and $1 million in total thereafter.

Operating Leases

We lease property, facilities and equipment under various operating leases. The majority of our total commitments on operating leases is the lease of the AmSouth Center located in Birmingham, Alabama. Our parent company guarantees all obligations under this lease agreement. Minimum future annual rental commitments on our operating leases as of December 31, 2003, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2004	$2
2005	2
2006	1
Total	$5

Rental expense on our operating leases for each of the years ended December 31, 2003, 2002, and 2001 was $3 million, $4 million and $5 million.

11. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan to provide benefits determined under a cash balance formula covering substantially all of its U.S. employees, including our employees. Prior to January 1, 2000, Sonat Inc., our former parent company, maintained a pension plan for our employees. On January 1, 2000, the Sonat pension plan was merged into El Paso's cash balance plan. Our employees who were active participants in the Sonat pension plan on December 31, 1999, receive the greater of cash balance benefits under the El Paso plan or Sonat plan benefits accrued through December 31, 2004.

El Paso also maintains a defined contribution plan covering its U.S. employees, including our employees. Prior to May 1, 2002, El Paso matched 75 percent of participant basic contributions up to 6 percent, with matching contributions being made to the plan's stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for matching contributions to be invested in the same manner as that of participant contributions. In March 2003, El Paso suspended the matching contribution. Effective July 1, 2003, El Paso began making matching contributions again at a rate of 50 percent of participant basic contributions up to 6 percent. El Paso is responsible for benefits accrued under its plans and allocates the related costs to its affiliates.

Other Postretirement Benefits

As a result of our merger with El Paso in October 1999, we offered a one-time election through an early retirement window for Sonat employees who were at least age 50 with 10 years of service on December 31, 1999, to retire on or before June 30, 2000, and keep benefits under Sonat's past retirement medical and life plans. Medical benefits for this closed group of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. El Paso reserves the right to change these benefits. Employees who retire after June 30, 2000, continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are prefunded to the extent these costs are recoverable through our rates. We expect to contribute $4 million to our other postretirement benefit plan in 2004.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. The benefit obligations and costs reported below, which include prescription drug coverage, do not reflect the impact of this legislation. Current accounting standards that are not yet effective may require changes to previously reported benefit information once they are finalized.

The following table presents the change in benefit obligation, change in plan assets, reconciliation of funded status, and components of net periodic benefit cost for other postretirement benefits as of and for the twelve months ended September 30 (the plan reporting date):

	2003	2002
	(In millions)	
Change in benefit obligation		
Benefit obligation at beginning of period	$ 81	$ 83
Interest cost	5	6
Participant contributions	1	1
Actuarial loss (gain)	27	(4)
Benefits paid	(6)	(5)
Benefit obligation at end of period	$108	$ 81
Change in plan assets		
Fair value of plan assets at beginning of period	$ 45	$ 49
Actual return on plan assets	7	(4)
Employer contributions	4	4
Participant contributions	1	1
Benefits paid	(6)	(5)
Fair value of plan assets at end of period	$ 51	$ 45
Reconciliation of funded status		
Under funded status as of September 30	$(57)	$(36)
Unrecognized actuarial loss	34	12
Net accrued benefit cost at December 31	$(23)	$(24)

Benefit costs include the following components for the year ended December 31:

	2003	2002	2001
		(In millions)	
Interest cost	$ 5	$ 6	$ 7
Expected return on plan assets	(2)	(2)	(3)
Net postretirement benefit cost	$ 3	$ 4	$ 4

Benefit obligations are based on actuarial estimates and assumptions. The following table details the weighted average assumptions we used for our other postretirement plan for 2003, 2002 and 2001:

	2003	2002	2001
Assumptions related to benefit obligations at September 30:			
Discount rate	6.00%	6.75%	
Assumptions related to benefit costs at December 31:			
Discount rate	6.75%	7.25%	7.75%
Long-term rate of return on plan assets[(1)]	7.50%	7.50%	7.50%

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 31% to 34% on postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on the target asset allocations of our investment portfolio.

Actuarial estimates for our postretirement benefits plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2003, gradually decreasing to 5.5 percent by the year 2008. Assumed health care cost trends can have a significant effect on the amounts reported for other postretirement benefit plan. A one-percentage point change in our assumed health care cost trends would have the following effects:

	2003	2002
	(In millions)	
One percentage point increase		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	$ 7	$ 7
One percentage point decrease		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	$(6)	$(7)

Other Postretirement Plan Assets. The following table provides the actual asset allocations in our postretirement plan as of September 30:

	Actual 2003	Actual 2002
Equity securities	29%	71%
Debt securities	62	9
Other	9	20
Total	100%	100%

The target allocation for the invested assets is 65% equity/35% fixed income. In late 2003, we modified our target asset allocations for our postretirement plan to increase our equity allocation to 65 percent of total plan assets. As of September 30, 2003, we had not yet adjusted our portfolio's investments to reflect this change in strategy. Other assets are held in cash for payment of benefits upon presentment. Any El Paso stock held by the plan is held indirectly through investments in mutual funds.

The primary investment objective of our plan is to ensure, that over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to support the benefit obligation to participants, retirees and beneficiaries. In meeting this objective, the plan seeks to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall in investment performance compared to investment objectives is the result of general economic and capital market conditions.

12. Common Stock

As of December 31, 2003 and 2002, we have 1,000 authorized shares of common stock, with a par value of $1 per share. In March 2003, we declared and paid a $600 million dividend, $310 million of which was a non-cash distribution of outstanding affiliated receivables and $290 million of which was cash.

13. Transactions with Major Customers

The following table shows revenues from major customers for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Scana Corporation[1]	$62	$62	$60
Alabama Gas Corporation[2]	45	44	44
Atlanta Gas Light Company[1][3]	29	29	29

(1) A significant portion of revenues received from a subsidiary of Scana Corporation resulted from firm capacity released by Atlanta Gas Light Company under terms allowed by our tariff.

(2) In 2003, Alabama Gas Corporation did not represent more than 10 percent of our revenues.

(3) In 2001, 2002 and 2003, Atlanta Gas Light Company did not represent more than 10 percent of our revenues.

14. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for each of the three years ended December 31:

	2003	2002	2001
		(In millions)	
Interest paid, net of capitalized interest	$75	$53	$43
Income tax payments	25	15	56

15. Investments in Unconsolidated Affiliates and Transactions with Affiliates

Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates are accounted for using the equity method of accounting and consist of our equity ownership interests in Citrus and Bear Creek.

Citrus. In March 2003, El Paso contributed its 50 percent ownership interest in Citrus to us. Enron owns the other 50 percent. Citrus owns and operates Florida Gas Transmission, a 4,886 mile regulated pipeline system that extends from producing regions in Texas to markets in Florida. As of December 31, 2003 and 2002, our investment in Citrus was $650 million and $606 million. Our investment in Citrus is limited to our ownership of the voting stock of Citrus, and we have no financial obligations, commitments or guarantees, either written or oral, to support Citrus.

The ownership agreements of Citrus provide each partner with a right of first refusal to purchase the ownership interest of the other partner. We have no obligations, either written or oral, to acquire Enron's ownership interest in Citrus in the event Enron must sell its interest as a result of its current bankruptcy proceedings. See Note 10 for further discussion of Enron's bankruptcy proceedings.

Enron serves as the operator for Citrus. Although Enron filed for bankruptcy, there have been minimal changes in the operations and management of Citrus as a result of their bankruptcy. Accordingly, Citrus has continued to operate as a jointly owned investment, over which we have significant influence, but not the ability to control.

Citrus has approximately $256 million in current maturities on its long-term debt due in 2004 which it intends to fund through the utilization of current working capital, future operating cash flows and the incurrence of additional indebtedness, if necessary.

Bear Creek. We hold a 50 percent ownership interest in Bear Creek, a joint venture with TSC, our affiliate. Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to the TGP system (an affiliated system), and our pipeline system under long-term contracts. Our investment in Bear Creek as of December 31, 2003 and 2002, was $138 million and $128 million. Under El Paso's $3 billion revolving credit facility, our ownership in Bear Creek is currently pledged as part of the overall collateral for the facility.

Summarized income statement and balance sheet information of our proportionate share of our unconsolidated affiliates for the years ended December 31, 2003, 2002 and 2001 and as of December 31, 2003 and 2002 are as follows:

	Years Ended December 31,		
	2003	2002	2001
	(In millions)		
Operating results data:			
Operating revenues	$241	$210	$177
Operating expenses	112	83	77
Income from continuing operations	50	55	54
Net income[(1)]	50	55	54

	December 31,	
	2003	2002
Financial position data:		
Current assets	$ 175	$ 206
Non-current assets	1,821	1,815
Short-term debt	129	13
Other current liabilities	70	92
Long-term debt	456	612
Other non-current liabilities	555	574
Equity in net assets[(1)]	786	730

(1) The difference between our proportionate share of our equity investments' net income and our earnings from unconsolidated affiliates reflected in our income statement and our proportionate share of their net equity and our overall investment in the balance sheet are due primarily to timing differences between the estimated and actual equity earnings from our investments.

Transactions with Affiliates

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We had advanced $153 million at December 31, 2003, at a market rate of interest which was 2.8%. At December 31, 2002, we had advanced $430 million at a market rate of interest which was 1.5%. These receivables are due upon demand; however, we do not anticipate settlement within the next twelve months. As of December 31, 2003 and 2002, we classified $153 million and $369 million as non-current note receivables from affiliates. See Note 2 for a discussion regarding our participation in and the collectibility of these receivables.

In March 2003, we distributed dividends from retained earnings totaling approximately $600 million to our parent including approximately $310 million of outstanding affiliated receivables and approximately $290 million in cash.

We had accounts payable to affiliates of $8 million at December 31, 2003, and $9 million at December 31, 2002. These balances arose in the normal course of our business. As a result of El Paso's credit rating downgrades, we maintained $10 million as of December 31, 2003 and 2002, in contractual deposits related to our Elba Island capacity contracts with EPME as discussed below. As a result of EPME assigning the capacity contracts to a subsidiary of British Gas, BG LNG Services, LLC in December 2003 and BG Energy Holdings, Ltd., also a subsidiary of British Gas, providing a parental guarantee, Southern LNG returned these deposits to EPME in January 2004.

During 2002 and 2001, we sold natural gas to EPME and recognized revenues of $2 million and $43 million. Natural gas sales to EPME during 2003 were less than $1 million. During 2002, EPME subscribed to all the available capacity at our Elba Island facility under a contract that extends to 2023. In 2003 and 2002, we recognized revenues of $28 million and $32 million related to this contract. EPME assigned this contract to BG LNG Services, LLC in December 2003. During 2003, 2002 and 2001, we transported gas for EPME and recognized transportation revenue of $2 million, $4 million and $7 million. We settled gas imbalance costs with EPME for the years ended 2003, 2002 and 2001 for $1 million, $2 million and $6 million. These amounts are recorded in operation and maintenance expense. These activities were entered into in the normal course of our business and are based on the same terms as non-affiliates.

El Paso allocates a portion of their general and administrative expenses to us. The allocation of expenses is based upon the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. For the years ended December 31, 2003, 2002 and 2001 the annual charges were $42 million, $41 million and $39 million. Beginning in 2001, TGP allocated payroll and other expenses associated with shared pipeline services to us. The allocated expenses are based on the estimated level of staff and their expenses to provide the services. For the years ended December 31, 2003, 2002 and 2001, the annual charges were $8 million, $5 million and $5 million. We believe that the allocation methods are reasonable.

The following table shows revenues and charges from our affiliates for each of the three years ended December 31:

	2003	2002 (In millions)	2001
Revenues from affiliates	$37	$45	$50
Operation and maintenance expense from affiliates	48	47	51

16. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				
	March 31	June 30	September 30 (In millions)	December 31	Total
2003					
Operating revenues	$120	$111	$111	$140	$482
Operating income	58	50	45	76	229
Net income	44	26	28	46	144
2002					
Operating revenues	$103	$100	$101	$125	$429
Operating income	50	45	43	64	202
Income before cumulative effect of accounting change	30	34	37	29	130
Cumulative effect of accounting change, net of income taxes	57	—	—	—	57
Net income	87	34	37	29	187

REPORT OF INDEPENDENT AUDITORS

To the Board of Directors and Stockholder of
Southern Natural Gas Company:

In our opinion, the consolidated financial statements listed in the Index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of Southern Natural Gas Company and its subsidiaries ("the Company") at December 31, 2003 and 2002, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We did not audit the consolidated financial statements of Citrus Corp. ("Citrus") for the year ended December 31, 2001. Citrus is an equity investment of the Company that comprised income of $41 million for the year ended December 31, 2001. Those statements were audited by other auditors whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it relates to the amount included for Citrus, is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Company's parent, El Paso Corporation, may be in default of covenants contained in its revolving credit facility and other financing transactions. Such an event of default could have a material impact on the Company's liquidity. The waivers have been obtained by El Paso Corporation, however, certain conditions must be satisfied to continue the effectiveness of the waivers.

As discussed in Note 5, the Company adopted Statement of Financial Accounting Standards No. 141, *Business Combinations,* and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* on January 1, 2002.

/s/ PricewaterhouseCoopers LLP

Birmingham, Alabama
March 24, 2004

SCHEDULE II

SOUTHERN NATURAL GAS COMPANY
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2003, 2002 and 2001
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2003					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	1	—	—	—	1
Legal reserves	—	—	1	—	1
Environmental reserves	4	3	—	(4)[1]	3
2002					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	2	—	—	(1)	1
Environmental reserves	11	—	—	(7)[1]	4
2001					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	2	—	—	—	2
Environmental reserves	14	—	—	(3)[1]	11

(1) Primarily payments made for environmental remediation.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Annual Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are properly authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. Southern Natural Gas Company's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in Southern Natural Gas Company's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in Southern Natural Gas Company's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Annual Report. The principal executive officer and principal financial officer note that there has not been any change in Internal Controls that occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Internal Controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to Southern Natural Gas Company and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certifications. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Annual Report.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of March 26, 2004, regarding our executive officers and directors. Directors are elected annually by our parent, and hold office until their successors are elected and duly qualified. Each executive officer named in the following table has been elected to serve until his successor is duly appointed or elected or until his earlier removal or resignation from office.

There are no family relationships among any of our executive officers or directors, and, unless described herein, no arrangement or understanding exists between any executive officer and any other person pursuant to which he was or is to be selected as an officer.

Name	Age	Position
John W. Somerhalder II	48	Director and Chairman of the Board
James C. Yardley	52	Director and President
Greg G. Gruber	56	Director, Senior Vice President, Chief Financial Officer and Treasurer

John W. Somerhalder II has been Director and Chairman of the Board of Southern Natural Gas since January 2000. Mr. Somerhalder has been Executive Vice President of El Paso since April 2000. He has been Chairman of the Board of Tennessee Gas Pipeline Company and El Paso Natural Gas Company since January 2000 and Chairman of the Board of ANR Pipeline Company and Colorado Interstate Gas Company since January 2001. Mr. Somerhalder was President of Tennessee Gas Pipeline from December 1996 to January 2000. He also served as Senior Vice President of El Paso from August 1992 to April 1996. He also holds director and/or officer positions with other of our affiliates.

James C. Yardley has been a Director and President of Southern Natural Gas since May 1998. He served as Vice President, Marketing and Business Development from April 1994 to April 1998. Prior to that time, Mr. Yardley served in various positions with Southern Natural Gas and Sonat Inc. since 1978. He also holds director and/or officer positions with other of our affiliates.

Greg G. Gruber has been a Director since June 2003 and has been Senior Vice President and Chief Financial Officer since January 2001 and Treasurer of Southern Natural Gas since November 2001. Mr. Gruber has served as Senior Vice President, Chief Financial Officer and Treasurer of our affiliate Tennessee Gas Pipeline since June 2003. He served as Senior Vice President and Chief Financial Officer of Tennessee Gas Pipeline from January 2001 to June 2001. Prior to that time, Mr. Gruber served as Vice President of Tennessee Gas Pipeline from January 1998 to January 2001. He also holds director and/or officer positions with other of our affiliates.

We are a wholly owned subsidiary of El Paso and rely on El Paso for certain support services. As a result, we do not have a separate corporate audit committee or audit committee financial expert. Also, we have not adopted a separate code of ethics. However, our executives are subject to El Paso's Code of Business Conduct which is available for your review at El Paso's website, www.elpaso.com.

ITEM 11. EXECUTIVE COMPENSATION

Our executive officers are compensated by us or TGP, our affiliate, for their services in such capacities. The following table and narrative text sets forth information concerning compensation paid by our affiliate to our president (considered our "chief executive officer") and our two other most highly compensated executive officers for services rendered to us and our affiliates in all capacities for services rendered to us during the last three fiscal years. We did not have any other executive officers other than the named executive officers at the end of 2003. The table also identifies the principal capacity in which each of the executives served us at the end of 2003.

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Other Annual Compensation ($) (3)	Restricted Stock Awards ($) (4)	Securities Underlying Options (#)	Long-Term Incentive Plan Payouts ($) (5)	All Other Compensation ($) (6)
John W. Somerhalder II	2003	$ 49,400						
Chairman of the Board	2002	$ 48,000						
	2001	$ 44,167						
James C. Yardley	2003	$265,008	$160,000	—	$ 0	0	$107,925	$ 264,831
President	2002	$250,008	$ 56,250	$36,000	$ 0	0	$ 0	$ 258,803
	2001	$240,417	$200,003	—	$99,997	101,375	$ 0	$1,289,785
Greg G. Gruber	2003	$ 17,200						
Senior Vice President,	2002	$ 16,000						
Chief Financial	2001	$ 14,084						
Officer and Treasurer								

(1) The amount reflected in this column for Messrs. Somerhalder and Gruber are amounts charged to us by TGP for the services rendered to us by Messrs. Somerhalder and Gruber since they divide their time between service to us and to our affiliates. Our affiliate pays Messrs. Somerhalder's and Gruber's base salary and charges back an 8 percent allocation to us. The amount charged back to us is derived by estimating the time and effort involved in providing services to us. The amount reflected in this column for Mr. Yardley reflects 100% of his base salary paid by us. Messrs. Somerhalder and Gruber may also receive stock options, restricted stock, pension plan benefits and other compensation and benefits from El Paso. Those benefits, if any, are not charged directly to us and are, therefore, not reflected in this table and not described elsewhere in this report. However, we do pay TGP for certain general and administrative costs, which may include the costs of certain compensation and benefits for officers (including Messrs. Somerhalder and Gruber) and employees. The amounts reflected in the salary column for 2003 and 2002 for Messrs. Somerhalder and Gruber include amounts for El Paso mandated reductions to fund certain charitable organizations.

(2) For fiscal year 2001, El Paso's incentive compensation plans required executives to receive a substantial part of their annual bonus in shares of restricted El Paso common stock. The amounts reflected in this column for Mr. Yardley for 2001 represent a combination of the market value of the restricted common stock and cash at the time awarded under the applicable El Paso incentive compensation plan.

(3) The amount reflected for Mr. Yardley in fiscal year 2002 is for a $36,000 perquisite and benefit allowance. Except as noted, the total value of the perquisites and other personal benefits received by Mr. Yardley in fiscal years 2003 and 2001 are not included in this column since they were below the Securities and Exchange Commission's reporting threshold.

(4) For fiscal year 2001, El Paso's incentive compensation plans provided for and encouraged participants to elect to take the cash portion of their annual bonus award in shares of restricted common stock. The amount reflected in this column for 2001 includes the market value of restricted common stock on the date of grant. The value of the El Paso shares of stock issued has declined significantly since the date of grant.

(5) For fiscal year 2003, the amount reflected in this column for Mr. Yardley is the value of shares of restricted stock on the date they vested. These shares had been reported in a long-term incentive table in El Paso's proxy statement for the year in which those shares of restricted stock were originally granted, along with the necessary performance measures necessary for their vesting. No long-term incentive payouts were made in fiscal years 2002 and 2001. In addition to the amount reflected in this column for 2003, Mr. Yardley realized $86,340 for the conversion of El Paso stock options into shares of El Paso common stock.

(6) The compensation reflected in this column for fiscal year 2003 includes El Paso's contributions to the El Paso Retirement Savings Plan and supplemental company match for the Retirement Savings Plan under the Supplemental Benefits Plan. Specifically, these amounts for fiscal year 2003 were $4,969 and $3,638 for Mr. Yardley. In addition, for fiscal year 2003 for Mr. Yardley, the amount in this column includes the value of a special retention payment in the amount $256,224.

El Paso Pension Plan

Effective January 1, 1997, El Paso amended its pension plan to provide pension benefits under a cash balance plan formula that defines participant benefits in terms of a hypothetical account balance.

Effective January 1, 2000, an initial account balance was established for each Sonat employee who was a participant in the Sonat pension plan (including Mr. Yardley) on December 31, 1999 due to the merger of Sonat Inc.'s plan into El Paso's pension plan. Prior to the pension plan merger, Sonat participants received pension benefits under a plan (the "Prior Sonat Plan") that defined monthly benefits based on final average earnings and years of service. The initial account balance was equal to the present value of the Prior Sonat Plan benefit as of December 31, 1999.

At the end of each calendar quarter, participant account balances are increased by an interest credit based on 5-Year Treasury bond yields, subject to a minimum interest credit of 4% per year, plus a pay credit equal to a percentage of salary and bonus. The pay credit percentage is based on the sum of age plus service at the end of the prior calendar year according to the following schedule:

Age Plus Service	Pay Credit Percentage
Less than 35	4%
35 to 49	5%
50 to 64	6%
65 and over	7%

Under El Paso's pension plan and applicable Internal Revenue Code provisions, compensation in excess of $200,000 cannot be taken into account and the maximum payable benefit in 2003 was $160,000. Any excess benefits otherwise accruing under El Paso's pension plan are payable under El Paso's Supplemental Benefits Plan. Participants may elect to receive benefits in the form of either a lump sum payment or actuarial equivalent monthly payments over a period of time not less than five years and not more than the participant's remaining life.

Participants with a Prior Sonat Plan benefit (including Mr. Yardley) are provided pension benefits that equal the greater of the cash balance formula benefit or the Prior Sonat Plan benefit accrued through the earlier of the date of termination or December 31, 2004. The Prior Sonat Plan benefit is computed as follows: (2.4% of the participant's average annual earnings during his five years of highest earnings for each year of pre-92 service (up to a total of 25 years)) minus (2.0% of estimated social security benefit for each year of pre-92 service (up to a total of 25 years)) plus (2.0% of the participant's average annual earnings during his five years of highest earnings for each year of post-91 service (up to a total of 30 years)) minus (1.667% of estimated social security benefit for each year of post-91 service (up to a total of 30 years)). The result from this Prior Sonat Plan formula cannot exceed 60% of the participant's average annual earnings during his five years of highest earnings minus 50% of the estimated social security benefit.

Amounts reported under Salary and Bonus for Mr. Yardley in this Form 10-K in the Summary Compensation Table approximate earnings as defined under the pension plan.

Estimated annual benefits payable from the pension plan and Supplemental Benefits Plan upon retirement at the normal retirement age (age 65) for Mr. Yardley is reflected below (based on assumptions that Mr. Yardley receives base salary shown in the Summary Compensation Table with no pay increases, receives 25% of maximum annual bonuses beginning with bonuses earned for fiscal year 2004, and cash balances are credited with interest at a rate of 4% per annum):

Named Executive	Credited Service(1)	Pay Credit Percentage During 2003	Estimated Annual Benefits
James C. Yardley	26.5	7%	$237,850

(1) Mr. Yardley's credited service shown is as of December 31, 2004.

Benefit Plans

The following is a description of El Paso benefit plans in which Mr. Yardley does, or is eligible, to participate. While Messrs. Somerhalder and Gruber may participate in these plans, because the costs of their participation are not charged back to us we have not addressed their participation. However, we do pay TGP for certain general and administrative costs, which may include the costs of certain compensation and benefits for officers (including Messrs. Somerhalder and Gruber) and employees. You should refer to El Paso's 2003 annual report on Form 10-K and proxy statement, when filed, for additional information on all of El Paso's benefit and equity plans and programs.

Severance Pay Plan. The Severance Pay Plan is a broad-based employee plan providing severance benefits following a "qualifying termination" for all salaried employees of El Paso and certain of its subsidiaries.

El Paso Key Executive Severance Protection Plan. This plan, initially adopted in 1992, provides severance benefits following a "change in control" of El Paso for certain officers of El Paso and certain of its subsidiaries, including Mr. Yardley. The benefits of the plan include: (1) an amount equal to three times the participant's annual salary, including maximum bonus amounts as specified in the plan; (2) continuation of life and health insurance for an 18-month period following termination; (3) a supplemental pension payment calculated by adding three years of additional credited pension service; (4) certain additional payments to the terminated employee to cover excise taxes if the payments made under the plan are subject to excise taxes on golden parachute payments; and (5) payment of legal fees and expenses incurred by the employee to enforce any rights or benefits under the plan. Benefits are payable for any termination of employment for a participant in the plan within two years of the date of a change in control, except where termination is by reason of death, disability, for cause or instituted by the employee for other than "good reason" (as defined in the plan). A change in control occurs if: (i) any person or entity becomes the beneficial owner of 20% or more of El Paso's common stock; (ii) any person or entity (other than El Paso) purchases the common stock by way of a tender or exchange offer; (iii) El Paso stockholders approve a merger or consolidation, sale or disposition or a plan of liquidation or dissolution of all or substantially all of El Paso's assets; or (iv) if over a two year period a majority of the members of the El Paso Board of Directors at the beginning of the period cease to be directors. A change in control has not occurred if El Paso is involved in a merger, consolidation or sale of assets in which the same stockholders of El Paso before the transaction own 80% of the outstanding common stock after the transaction is complete. This plan generally may be amended or terminated at any time, provided that no amendment or termination may impair participants' rights under the plan or be made following the occurrence of a change in control. This plan is closed to new participants, unless the El Paso Board determines otherwise.

El Paso Supplemental Benefits Plan. This plan provides for certain benefits to officers and key management employees of El Paso and its subsidiaries. The benefits include: (1) a credit equal to the amount that a participant did not receive under El Paso's Pension Plan because the Pension Plan does not consider deferred compensation (whether in deferred cash or deferred restricted common stock) for purposes of calculating benefits and eligible compensation is subject to certain Internal Revenue Code limitations; and (2) a credit equal to the amount of El Paso's matching contribution to El Paso's Retirement Savings Plan that cannot be made because of a participant's deferred compensation and Internal Revenue Code limitations. The plan may not be terminated so long as the Pension Plan and/or Retirement Savings Plan remain in effect. The management committee of this plan designates who may participate and also administers the plan. Benefits under El Paso's Supplemental Benefits Plan are paid upon termination of employment in a lump-sum payment, in annuity or in periodic installments. In the event of a change in control (as defined under the El Paso Key Executive Severance Protection Plan), the supplemental pension benefits become fully vested and nonforfeitable.

El Paso Senior Executive Survivor Benefits Plan. This plan provides certain senior executives (including Mr. Yardley) of El Paso and its subsidiaries who are designated by the plan administrator with survivor benefit coverage in lieu of the coverage provided generally for employees under El Paso's group life insurance plan. The amount of benefits provided, on an after-tax basis, is two and one-half times the executive's annual salary. Benefits are payable in installments over 30 months beginning within 31 days after the executive's death, except that the plan administrator may, in its discretion, accelerate payments.

El Paso Benefits Protection Trust Agreement

El Paso maintains a trust for the purpose of funding certain of its employee benefit plans (including the El Paso Key Executive Severance Protection Plan). The trust consists of a trustee expense account, which is used to pay the fees and expenses of the trustee, and a benefit account, which is made up of three subaccounts and used to make payments to participants and beneficiaries in the participating plans. The trust is revocable by El Paso at any time before a "threatened change in control" (which is generally defined to include the commencement of actions that would lead to a "change in control" (as defined under the El Paso Key Executive Severance Protection Plan)) as to assets held in the trustee expense account, but is not revocable (except as provided below) as to assets held in the benefit account at any time. The trust generally becomes fully irrevocable as to assets held in the trust upon a threatened change in control. The trust is a grantor trust for federal tax purposes, and assets of the trust are subject to claims by El Paso's general creditors in preference to the claims of plan participants and beneficiaries. Upon a threatened change in control, El Paso must deliver $1.5 million in cash to the trustee expense account. Prior to a threatened change in control, El Paso may freely withdraw and substitute the assets held in the benefit account, other than the initially funded amount; however, no such assets may be withdrawn from the benefit account during a threatened change in control period. Any assets contributed to the trust during a threatened change in control period may be withdrawn if the threatened change in control period ends and there has been no threatened change in control. In addition, after a change in control occurs, if the trustee determines that the amounts held in the trust are less than "designated percentages" (as defined in the Trust Agreement) with respect to each subaccount in the benefit account, the trustee must make a written demand on El Paso to deliver funds in an amount determined by the trustee sufficient to attain the designed percentages. Following a change in control and if the trustee has not been requested to pay benefits from any subaccount during a "determination period" (as defined in the Trust Agreement), El Paso may make a written request to the trustee to withdraw certain amounts which were allocated to the subaccounts after the change in control occurred. The trust generally may be amended or terminated at any time, provided that no amendment or termination may result, directly or indirectly, in the return of any assets of the benefit account to El Paso prior to the satisfaction of all liabilities under the participating plans (except as described above) and no amendment may be made unless El Paso, in its reasonable discretion, believes that such amendment would have no material adverse effect on the amount of benefits payable under the trust to participants. In addition, no amendment may be made after the occurrence of a change in control which would (i) permit El Paso to withdraw any assets from the trustee expense account, (ii) directly or indirectly reduce or restrict the trustee's rights and duties under the trust, or (iii) permit El Paso to remove the trustee following the date of the change in control.

El Paso Stockholder Approved Plans

El Paso 2001 Omnibus Incentive Compensation Plan. This plan provides for the grant to officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. A maximum of 6,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator designates which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a "change in control" (defined in substantially the same manner as under the El Paso Key Executive Severance Protection Plan) occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; (3) designated amounts of performance units become fully vested; (4) all restrictions placed on awards of restricted common stock automatically lapse; and (5) the current year's target bonus amount becomes payable for each officer participating in the plan within 30 days, assuming target levels of performance were achieved by El Paso and the officer for the year in which the change in control occurs, or the prior year if target levels have not been established for the current year, except that no bonus amounts will become payable in connection with a change in control that results solely from a change to the Board of Directors of El Paso. The plan generally may be amended or terminated at any time. Any amendment following a change in control that impairs participant's rights requires participant consent.

El Paso 1999 Omnibus Incentive Compensation Plan and El Paso 1995 Omnibus Compensation Plan — terminated plans. These plans provided for the grant to eligible officers and key employees of El Paso and its subsidiaries of stock options, stock appreciation rights, limited stock appreciation rights, performance units and restricted stock. These plans have been replaced by the El Paso 2001 Omnibus Incentive Compensation Plan. Although these plans have been terminated with respect to new grants, certain stock options and shares of restricted common stock remain outstanding under them. If a "change in control" of El Paso occurs, all outstanding stock options become fully exercisable and restrictions placed on restricted common stock lapse. For purposes of the plans, the term "change in control" has substantially the same meaning given such term in the El Paso Key Executive Severance Protection Plan.

El Paso Non-stockholder Approved Plans

El Paso Strategic Stock Plan. This plan is an equity compensation plan that has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted common stock to non-employee members of the El Paso Board of Directors, officers and key employees of El Paso and its subsidiaries primarily in connection with El Paso's strategic acquisitions. A maximum of 4,000,000 shares in the aggregate may be subject to awards under this plan. The plan administrator determines which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. If a change in control, as defined earlier under the Key Executive Severance Protection Plan, occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted common stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair a participant's current rights under the plan.

El Paso Restricted Stock Award Plan for Management Employees. This plan is an equity compensation plan which has not been approved by the stockholders. The plan provides for the granting of restricted shares of El Paso's common stock to management employees (other than executive officers and directors) of El Paso and its subsidiaries for specific accomplishments beyond that which are normally expected and which will have a significant and measurable impact on the long-term profitability of El Paso. A maximum of 100,000 shares in the aggregate may be subject to awards under this plan. The plan administrator designates which employees are eligible to participate, the amount of any grant and the terms and conditions (not otherwise specified in the plan) of such grant. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair a participant's current rights under the plan.

El Paso Omnibus Plan for Management Employees. This plan is an equity compensation plan which has not been approved by the stockholders. This plan provides for the grant of stock options, stock appreciation rights, limited stock appreciation rights and shares of restricted common stock to salaried employees (other than employees covered by a collective bargaining agreement) of El Paso and its subsidiaries. A maximum of 58,000,000 shares in the aggregate may be subject to awards under this plan. If a change in control, as defined earlier under the Key Executive Severance Protection Plan, occurs: (1) all outstanding stock options become fully exercisable; (2) stock appreciation rights and limited stock appreciation rights become immediately exercisable; and (3) all restrictions placed on awards of restricted common stock automatically lapse. The plan generally may be amended or terminated at any time, provided that no amendment or termination may impair a participant's current rights under the plan.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

None of our Common Stock is held by any director or executive officer. No family relationship exists between any of our directors or executive officers. The following information relates to the only entity known to us to be the beneficial owner, as of March 26, 2004, of more than five percent of our voting securities.

Title of Class	Name	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	El Paso Corporation 1001 Louisiana Street Houston, Texas 77002	1,000 shares	100%

The following table sets forth, as of March 26, 2004, certain information with respect to the following individuals to the extent they own shares of common stock of El Paso, our parent.

Title of Class	Name of Beneficial Owner	Beneficial Ownership (excluding options)	Stock Options(1)	Total	Percent of Class
El Paso Common Stock	John W. Somerhalder II	322,306	439,250	761,556	*
El Paso Common Stock	James C. Yardley	59,729	217,875	277,604	
El Paso Common Stock	Greg G. Gruber	59,298	160,820	220,118	
El Paso Common Stock	All directors and executive officers as a group (3 persons)	441,333	817,945	1,259,278	

* Less than 1%

(1) The directors and executive officers have the right to acquire the shares of common stock reflected in this column within 60 days of March 26, 2004, through the exercise of stock options.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

We are currently a wholly owned subsidiary of El Paso. El Paso owns 100% of our outstanding stock and has the right to elect all of our directors. We share office space, personnel, and other administrative services with El Paso. The costs of such services are allocated by El Paso to us and other affiliates. As described in Item 11 above, TGP, our affiliate, pays Messrs. Somerhalder's and Gruber's base salary and charges back an 8 percent allocation to us, and we pay 100% of the costs associated with Mr. Yardley's employment. The amount charged back to us is derived by estimating the time and effort involved in providing services to us. In addition, there are other shared personnel that may include officers who function as both our representatives and those of El Paso and its subsidiaries. We pay TGP for certain general and administrative costs, which may include the costs of certain compensation and benefits for officers (including Messrs. Somerhalder and Gruber) and other employees. Some of these shared directors, officers and employees own and are awarded from time to time shares, or options to purchase shares, of El Paso; accordingly, their financial interests may not always be aligned completely with ours.

Historically, El Paso's and its subsidiaries have contributed certain assets and ownership interests to us. In March 2003, El Paso contributed its 50 percent ownership interest in Citrus to us. We were required to reflect this investment in Citrus at its historical cost and include it in our financial statements for all periods presented. Before we enter into such a transaction, we determine whether the proposed transaction (i) would comply with the requirements under our indentures and credit agreements, and (ii) would comply with substantive law.

A discussion of certain agreements, arrangements and transactions between or among us and El Paso and its subsidiaries is summarized in Part II, Item 8, Financial Statements and Supplementary Data, Note 15.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Fees for the years ended December 31, 2003 and 2002 of $640,000 and $470,000 were for professional services rendered by PricewaterhouseCoopers LLP for the audits of the consolidated financial statements of Southern Natural Gas Company, the review of documents filed with the Securities and Exchange Commission, consents, and the issuance of comfort letters. No other audit-related, tax or other services were provided by our auditors for the years ended December 31, 2003 and 2002.

We are a wholly owned subsidiary of El Paso and do not have a corporate audit committee. El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. For a description of El Paso's pre-approval policies for audit and non-audit related services, see El Paso Corporation's proxy statement.

PART IV

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

(a) The following documents are filed as a part of this report:

1. Financial statements.

The following consolidated financial statements are included in Part II, Item 8 of this report:

The following financial statements of our equity investment are included on the following pages of this report:

2. Financial statement schedules.

All other schedules are omitted because they are not applicable, or the required information is disclosed in the financial statements or accompanying notes.

(b) Reports on Form 8-K.

None.

Citrus Corp. and Subsidiaries
Consolidated Financial Statements
Years Ended December 31, 2003, 2002 and 2001
with Report of Independent Auditor

CITRUS CORP. AND SUBSIDIARIES

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Report of Independent Auditors

To the Board of Directors and Stockholders of
Citrus Corp. and Subsidiaries:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, stockholders' equity and cash flows present fairly, in all material respects, the financial position of Citrus Corp. and Subsidiaries (the "Company") at December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 24, 2004

REPORT OF INDEPENDENT AUDITORS

Board of Directors
Citrus Corp.

We have audited the accompanying statements of income, stockholder's equity and cash flows for the year ended December 31, 2001 of Citrus Corp. and Subsidiaries. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 arrangement, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statement referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Citrus Corp. and Subsidiaries for the years ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

/s/ Ernst & Young LLP

March 15, 2002
Birmingham, AL

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
(In Thousands)	2003	2002
ASSETS		
Current Assets		
Cash and cash equivalents	$ 125,226	$ 114,682
Trade and other receivables		
Customers, net of allowance of $77 and $77	39,713	49,155
Income taxes	—	3,647
Price risk management assets	15,024	40,088
Materials and supplies	2,915	3,337
Other	4,294	6,796
Total Current Assets	187,172	217,705
Deferred Charges		
Unamortized debt expense	9,051	10,891
Price risk management assets	58,492	107,988
Other	108,380	54,618
Total Deferred Charges	175,923	173,497
Property, Plant and Equipment, at cost		
Completed Plant	4,023,762	3,737,804
Construction work-in-progress	35,638	176,484
Total property, plant and equipment, at cost	4,059,400	3,914,288
Less – accumulated depreciation and amortization	1,072,072	1,004,345
Net Property, Plant and Equipment	2,987,328	2,909,943
TOTAL ASSETS	$ 3,350,423	$ 3,301,145

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

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(In Thousands, Except Share Data)	December 31, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Long-term debt due within one year	$ 256,159	$ 25,409
Accounts payable		
Trade	30,396	38,543
Affiliated companies	20,086	18,964
Accrued liabilities		
Interest	19,054	21,345
Income taxes	1,148	—
Other taxes	10,349	9,107
Price risk management liabilities	25,136	20,681
Exchange gas imbalances, net	12,320	1,499
Other	283	994
Total Current Liabilities	374,931	136,542
Long-Term Debt	908,972	1,224,580
Deferred Credits		
Deferred income taxes	676,341	652,070
Price risk management liabilities	80,446	59,215
Other	13,618	10,045
Total Deferred Credits	770,405	721,330
Stockholders' Equity		
Common stock, $1 par value; 1,000 shares authorized, issued and outstanding	1	1
Additional paid-in capital	634,271	634,271
Accumulated other comprehensive income	(17,247)	(18,453)
Retained earnings	679,090	602,874
Total Stockholders' Equity	1,296,115	1,218,693
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,350,423	$ 3,301,145

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

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(In Thousands)	Year Ended December 31, 2003	2002	2001
Revenues			
Gas sales	$ 104,370	$ 102,166	$ —
Gas transportation, net	442,010	419,636	351,638
	546,380	521,802	351,638
Costs and Expenses			
Natural gas purchased	99,130	91,925	—
Operations and maintenance	117,086	89,993	77,368
Depreciation	44,462	38,041	31,771
Amortization	20,060	20,060	20,061
Taxes – other than income taxes	27,436	21,859	28,594
	308,174	261,878	157,794
Operating Income	238,206	259,924	193,844
Other Income (Expense)			
Interest expense, net	(104,653)	(92,668)	(86,946)
Allowance for funds used during construction	5,804	17,141	13,645
Other, net	(14,587)	(28,082)	10,520
	(113,436)	(103,609)	(62,781)
Income Before Income Taxes	124,770	156,315	131,063
Income Tax Expense	48,554	59,728	50,735
Net Income	$ 76,216	$ 96,587	$ 80,328

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

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In Thousands)	Year Ended December 31, 2003	2002	2001
Common Stock			
Balance, beginning and end of year	$ 1	$ 1	$ 1
Additional Paid-in Capital			
Balance, beginning and end of year	634,271	634,271	634,271
Accumulated Other Comprehensive Income (Loss):			
Balance, beginning of year	(18,453)	(6,713)	(6,692)
Deferred loss on cash flow hedge	—	(12,280)	—
Recognition in earnings of previously deferred (gains) and losses related to derivative instruments used as cash flow hedges	1,206	540	(21)
Balance, end of year	(17,247)	(18,453)	(6,713)
Retained Earnings			
Balance, beginning of year	602,874	506,287	425,959
Net income	76,216	96,587	80,328
Balance, end of year	679,090	602,874	506,287
Total Stockholders' Equity	$ 1,296,115	$ 1,218,693	$ 1,133,846

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

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)	Twelve Months Ended December 31, 2003	2002	2001
Cash Flows From Operating Activities			
Net income	$ 76,216	$ 96,587	$ 80,328
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	64,522	58,101	51,832
Amortization of hedge loss in other comprehensive income	1,206	540	(21)
Amortization of premium and swap hedge loss in long term debt	392	176	—
Amortization of regulatory assets and other deferred charges	12,000	2,609	1,307
Deferred income taxes	24,271	56,154	33,536
Fair value loss of reverse swap	—	2,575	—
Non-cash interest income	—	(2,025)	—
Price risk management fair market valuation revaluation	20,599	22,897	(6)
Allowance for funds used during construction	(5,804)	(17,141)	(13,645)
Changes in assets and liabilities			
Changes in working capital			
Trade and other receivables	9,443	21,634	17,894
Materials and supplies	422	350	322
Trade and other payables	(7,029)	(2,219)	(20,407)
Accrued liabilities	3,746	(5,711)	37
Other current assets and liabilities	9,863	304	15,361
Subtotal for charges in working capital	16,445	14,358	13,207
Price risk management assets and liabilities	7,150	(22,781)	11,853
Other, net	16,401	(19,224)	(32,195)
Net Cash Provided by Operating Activities	233,398	192,826	146,196
Cash Flows From Investing Activities			
Additions to property, plant and equipment	(142,334)	(242,804)	(198,836)
Allowance for funds used during construction	5,804	17,141	13,645
Retirements and disposition of property, plant and equipment, net	(1,074)	2,444	(526)
Net Cash Used in Investing Activities	(137,604)	(223,219)	(185,717)
Cash Flows From Financing Activities			
Proceeds from issuance of long-term debt	—	250,000	74,700
Long-term debt finance costs	—	(2,743)	(2,021)
Repayment of long-term debt	(59,500)	(74,700)	—
Principal payments on long-term debt	(25,750)	(25,750)	(25,750)
Anticipatory hedge settlement (other comprehensive income)	—	(12,280)	—
Interest rate swap settlement	—	(550)	—
Related party payment	—	—	80,000
Short-term bank borrowings, net	—	—	(80,000)
Net Cash Provided by/(Used in) Financing Activities	(85,250)	133,977	46,929
Increase (Decrease) in Cash and Cash Equivalents	10,544	103,584	7,408
Cash and Cash Equivalents, Beginning of Year	114,682	11,098	3,690
Cash and Cash Equivalents, End of Year	$ 125,226	$ 114,682	$ 11,098

Additional cash flow information:
The Company made the following interest and income tax payments:

Interest paid	$ 105,641	$ 90,284	$ 92,468
Income taxes paid	19,488	12,462	20,029

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

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Reporting Entity

Citrus Corp. (Citrus), a holding company formed in 1986, owns 100% of the stock of Florida Gas Transmission Company (Transmission), Citrus Trading Corp. (Trading) and Citrus Energy Services, Inc. (CESI), collectively the Company. The stock of the Company is owned 50% by El Paso Citrus Holdings, Inc. (EPCH), a wholly owned subsidiary of Southern Natural Gas Company (Southern), as transferred by Southern in January 2004, and 50% by Enron Corp. (Enron). Southern's 50% ownership had previously been contributed by its parent, El Paso Corporation (El Paso) in March 2003. Pursuant to Enron's filed Plan of Reorganization, Enron has formed a new operating entity, CrossCountry Energy LLC (CCE), and intends to contribute its interest in the Company to a new wholly-owned, direct subsidiary of CCE, CrossCountry Citrus Corp. Although bankruptcy court approval for the contribution and separation has been received, certain approvals are still required. These approvals are expected to be completed in 2004.

Transmission, an interstate gas pipeline extending from South Texas to South Florida, is engaged in the interstate transmission of natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Trading ceased all trading activities effective the fourth quarter of 1997, but continues to fulfill its obligations under the remaining gas purchase and gas sale contracts. Trading buys natural gas primarily from an affiliate of Southern, El Paso Merchant Energy and sells to Auburndale Power Partners, LP and Progress Energy Florida, Inc. Trading is evaluating opportunities to sell or assign its remaining contracts.

CESI primarily provides transportation management and financial services to customers of Transmission. CESI terminated its O&M business due to increased insurance costs and pipeline integrity legislation that affects operators.

In October 2002, and May and July 2003, Transmission and Trading filed several claims and amendments of claims with the United States Bankruptcy Court for the Southern District of New York against Enron and other affiliated bankrupt companies, aggregating $220.6 million. Of these claims, Transmission has filed claims totaling $68.1 million and Trading totaling $152.5 million. Transmission and Trading claims pertaining to contracts rejected by Enron North America Corp. (ENA) are $29.5 million and $152.3 million, respectively (see Note 14).

(2) Significant Accounting Policies

Regulatory Accounting – Transmission is subject to regulation by the FERC. Transmission's accounting policies generally conform to Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded under accounting principles generally accepted in the United States for non-regulated entities.

Principles of Consolidation – The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany transactions and accounts have been eliminated in consolidation.

Cash and Cash Equivalents – Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of these investments.

Materials and Supplies – Materials and supplies are valued at the lower of cost or market value. Materials transferred out of warehouses are priced out at average cost.

(2) Significant Accounting Policies (continued)

Revenue Recognition – Revenues consist primarily of gas transportation services. Reservation revenues on firm contracted capacity are recognized ratably over the contract period. For interruptible or volumetric based services, revenues are recorded upon the delivery of natural gas to the agreed upon delivery point. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. Transmission is subject to FERC regulations and, as a result, revenues collected may be required to be refunded in a final order in the pending rate proceeding (see Note 10) or as a result of a rate settlement. Reserves are established for these potential refunds.

Accounting for Derivative Instruments – The Company engages in price risk management activities for both trading and non-trading activities and accounts for these under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (see Note 4). Instruments utilized in connection with trading activities are accounted for using the mark-to-market method and are reflected at fair value as Assets and Liabilities from Price Risk Management Activities in the Consolidated Balance Sheets. Earnings from revaluation of price risk management assets and liabilities are included in Other Income (Expense). Cash flow hedge accounting is utilized for non-trading purposes to hedge the impact of interest rate fluctuations. Unrealized gains and losses from cash flow hedges are recognized according to SFAS No. 133 as other comprehensive income, and subsequently recognized in earnings in the same periods as the hedged forecasted transaction affects earnings. In instances where the hedge no longer qualifies as effective, hedge accounting is terminated prospectively and the accumulated gain or loss is recognized in earnings in the same periods during which the hedged forecasted transaction affects earnings. Where fair value hedge accounting is appropriate, the offset that is attributed to the risk being hedged is recorded as an adjustment to the hedged item.

Property, Plant and Equipment (See Note 11) — Property, Plant and Equipment consists primarily of natural gas pipeline and related facilities. The Company amortizes that portion of its investment in Transmission and other subsidiaries which is in excess of historical cost (acquisition adjustment) on a straight-line basis at an annual composite rate of 1.6% based upon the estimated remaining useful life of the pipeline system. Transmission has provided for depreciation of assets net of estimated salvage value, on a straight-line basis, at an annual composite rate of 1.66%, 1.52%, and 1.53% for 2003, 2002, and 2001, respectively. The overall remaining useful life for Transmission's assets at December 31, 2003, is 41 years.

Property, Plant and Equipment is recorded at its original cost. Transmission capitalizes direct costs, such as labor and materials, and indirect costs, such as overhead, interest and an equity return component (see following paragraph). Costs of replacements and renewals of units of property are capitalized. The original costs of units of property retired are charged to the depreciation reserves, net of salvage and removal costs. Transmission charges to maintenance expense the costs of repairs and renewal of items determined to be less than units of property.

The allowance for funds used during construction consists, in general, of the net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used (the AFUDC rate). The allowance is determined by applying the AFUDC rate to the amount of construction work-in-progress. Capitalization begins at the time the Company begins the continuous accumulation of costs in a construction work order on a planned progressive basis and ends when the facilities are placed in service.

The Company applies the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* to account for asset impairments. Under this standard, an asset is evaluated for impairment when events or circumstances indicate that a long-lived asset's carrying

(2) Significant Accounting Policies (continued)

value may not be recovered. These events include market declines, changes in the manner in which an asset was intended to be used, decisions to sell an asset, and adverse changes in the legal or business environment such as adverse actions by regulators.

Compressor Overhaul Expenditures – In 2003, Transmission changed its method of accounting for compressor overhaul costs by adopting a method of current expense recognition of compressor overhaul costs. This change was the result of Management's determination that such costs previously deferred would not be recovered through future tariff rates. In prior years, such costs were deferred and amortized ratably over the expected service life of the applicable overhaul item. A remaining unamortized balance of $7.0 million applicable to the previous method was expensed in 2003. An additional amount of $6.5 million related to 2003 overhaul costs, which would have been deferred under the previous methodology, was also expensed.

Income Taxes (See Note 5) – The Company accounts for income taxes under the provisions of SFAS No. 109, *Accounting for Income Taxes.* SFAS No. 109 provides for an asset and liability approach to accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases.

Trade Receivables – The Company establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. The Company considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. Unrecovered trade accounts receivable charged against the allowance for doubtful accounts were $0.3 and $22.2 million in 2003 and 2002, respectively.

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 disclosures 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 those estimates.

Reclassifications – Certain reclassifications have been made to the consolidated financial statements for prior years to conform with the current year presentations with no impact on reported net income or stockholders' equity.

(3) Long-Term Debt and Other Financing Arrangements

Long-term debt outstanding at December 31, 2003, and 2002 was as follows (in thousands):

	2003	2002
Citrus		
11.100% Notes due 1998-2006	$ —	$ 78,750
8.490% Notes due 2007-2009	90,000	90,000
	90,000	168,750
Transmission		
9.750% Notes due 1999-2008	32,500	39,000
8.630% Notes due 2004	250,000	250,000
10.110% Notes due 2009-2013	70,000	70,000
9.190% Notes due 2005-2024	150,000	150,000
7.625% Notes due 2010	325,000	325,000
7.000% Notes due 2012	250,000	250,000
Unamortized Debt Premium and Swap Loss	(2,369)	(2,761)
	1,075,131	1,081,239
Total Outstanding	1,165,131	1,249,989
Long-Term Debt Due Within One Year	(256,500)	(25,750)
Unamortized Debt Premium and Swap Loss Within One Year	341	341
	$ 908,972	$ 1,224,580

Annual maturities and sinking fund requirements on long-term debt outstanding as of December 31, 2003 were as follows (in thousands):

Year	Principal Amount	Amortization *(1)*	Total
2004	$ 256,500	$ (341)	$ 256,159
2005	14,000	(341)	13,659
2006	14,000	(341)	13,659
2007	44,000	(341)	43,659
2008	44,000	(341)	43,659
Thereafter	795,000	(664)	794,336
	$ 1,167,500	$ (2,369)	$ 1,165,131

(1) Amortization of the debt premium and swap loss recognized on financing arrangements.

Transmission's 8.63% Notes are due to be repaid in November 2004 in the amount of $250 million. Also in 2004, Transmission has due an additional $6.5 million under its 9.75% Notes. Management intends to fund this $256.5 million in current maturities through the utilization of current working capital, future operating cash flows and incurrence of additional indebtedness. The portion of current obligations due which are not repaid through current working capital and future operating cash flows will be refinanced under new borrowing agreements or the restoration of Transmission's ability to borrow on its $70 million revolving credit facility (see below). Transmission may incur additional debt to refinance maturing obligations if the refinancing does not increase aggregate indebtedness, and thereafter, if Transmission and the Company's consolidated debt does

(3) Long-Term Debt and Other Financing Arrangements (continued)

not exceed specific debt to total capitalization ratios, as defined. Incurrence of additional indebtedness to refinance the current maturities would not result in a debt to capitalization ratio exceeding these limits.

Citrus has note agreements that contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets, the payment of dividends, and maintaining certain restrictive financial covenants. The agreements relating to Transmission's promissory notes include, among other things, restrictions as to the payment of dividends and maintaining certain restrictive financial covenants. As of December 31, 2003, the Company was in compliance with both affirmative and restrictive covenants of the note agreements.

All of the debt obligations of Citrus and Transmission have events of default which contain commonly used cross-default provisions. An event of default by either Citrus or Transmission on any of their borrowed money obligations, in excess of certain thresholds which is not cured within defined grace periods, would cause the other debt obligations of Transmission and Citrus to be accelerated. As discussed below, Transmission has obtained a waiver on its revolving credit facility; however, there are no outstanding borrowings under this facility which could cause an event of cross-default.

Transmission has a committed revolving credit agreement of $70 million (the "Revolver"), of which none was outstanding at December 31, 2003. The committed amount under this agreement was increased to $210 million in April 2002 then reduced to $70 million in July 2002. Citrus absolutely and unconditionally guaranteed the obligations of Transmission under the line of credit agreement. On October 28, 2002, the Company sought and obtained a 60-day waiver (the "Waiver") of the requirement of Trading to hedge any open gas contracts within 45 days of knowledge of such open contracts (see Note 4). The Waiver has been renewed periodically since it was initially granted. Under the Waiver, Transmission is prohibited from drawing under the facility, but is permitted to issue letters of credit, provided they are cash collateralized (see Note 18).

Transmission has an aggregate of $0.6 million in letters of credit under the revolving credit agreement. Per the terms of the Waiver, these issued and outstanding letters of credit are collateralized with cash. Cash collateral deposits of $2.6 million from Transmission and deposits totaling $13.8 million from Trading were required in 2002 to support fully collateralized issued letters of credit (see Note 12).

Citrus also had a line of credit of $30 million. Transmission absolutely and unconditionally guaranteed the obligations of Citrus under the line of credit agreement. Citrus terminated this line of credit in 2002.

Citrus had also entered into a loan sales facility agreement in 2000 with a capacity of $40 million. Transmission had absolutely and unconditionally guaranteed the obligations of Citrus under these facilities. Citrus terminated this line of credit in 2002.

Transmission sold $250 million of 144A bonds without registration rights in July 2002. These notes pay interest of 7% biannually on August 1 and February 1 of each year. The entire principal amount is due July 17, 2012.

In October 2003, Citrus paid the remaining principal of $78.8 million on the 11.100% Note due in 2006 and incurred a $0.7 million pre-payment expense.

(4) Derivative Instruments

The Company determined that its gas purchase contracts for resale and related gas sales contracts are derivative instruments and records these at fair value as price risk management assets

(4) Derivative Instruments (continued)

and liabilities under SFAS No. 133, as amended. The valuation is calculated using a discount rate adjusted for the Company's borrowing premium of 250 basis points, which creates an implied reserve for credit and other related risks. The Company estimated the fair value of all derivative instruments based on quoted market prices, current market conditions, estimates obtained from third-party brokers or dealers, or amounts derived using internal valuation models. In 2003, the Company changed its method of presenting price risk management assets and liabilities to reflect the fair market value of specific contracts. In prior years, the Company presented price risk management assets and liabilities at the net present value of the expected future cash flows associated with the respective sales or purchase contracts. The prior year balances for the price risk management assets and liabilities of $684.7 million and $627.5 million, respectively, have been reclassified to conform with the current year presentation. This change in methodology does not have an impact on the consolidated statements of income or cash flows. At December 31, 2003 and 2002, under the specific contracts presentation, the fair value for the price risk management assets and liabilities was $73.5 million and $105.6 million, and $148.1 million and $79.9 million, respectively. The Company performs a quarterly revaluation on the carrying balances that is reflected in current earnings. The impact to earnings from revaluation, mostly due to price fluctuations and contract status, was a loss of $20.6, $22.9, and $0.0 million for 2003, 2002, and 2001, respectively.

ENA ceased performing under its purchase and sales contracts with Trading in December 2001. Subsequent to such date, Trading assumed responsibility for performance under the respective contracts and continued to transact business under the terms of these contracts throughout 2003 and 2002. As a result of the foregoing, Trading has reported revenues and expenses under such contracts on a gross basis for the years ended December 31, 2003 and 2002, due to Trading becoming the primary obligor under such contracts. Prior to 2002, such revenues and costs were reported net, as a component of Other Income (Expense) in the statements of income due to ENA bearing the primary obligations of such contracts.

Prior to the Enron bankruptcy, the principal counterparty to Trading's gas purchase and sale agreements (as well as swaps) was ENA. ENA has rejected these contracts in bankruptcy. A pre-petition gas purchase payable to ENA of $12.4 million was reversed in 2003 when it was determined that the Company had a right of offset against claims for pre-petition receivables. Pursuant to an existing operating agreement (rejected by ENA in 2003 but under which an El Paso affiliate is still performing), an affiliate of El Paso was required to buy gas, purchased from a significant third party, that exceeded the requirements of existing sales contracts. Under this third party contract, gas was purchased primarily at rates based upon a formula. This gas was then sold primarily at market rates. On April 16, 2003, the significant third party supplier terminated the supply contract. Trading currently only purchases the requirements to fulfill existing sales contracts from third parties at market rates. As a result of these developments, the cash flow stream is now dependent on variable pricing, whereas before Enron's bankruptcy, the cash flow stream was fixed. The quarterly valuations are based on management's best estimate of the fair value of the underlying contracts. Changes in the future pricing projections could lead to material differences in the valuation of the derivative instruments.

Due to a dispute (see Note 14) during 2003, Duke Energy LNG Sales, Inc. (Duke) discontinued performance under a natural gas purchase and supply contract between it and Trading and subsequently terminated the contract. As a result of this contract termination, during 2003, Trading discontinued the application of fair market value accounting for this contract, and wrote off the value of the related price risk management assets as a charge to Other Income/(Expense) in the accompanying statement of operations. Pursuant to the terms of the contract and also during 2003, Trading issued to Duke, the counterparty, a termination invoice for approximately $187 million. As a

(4) Derivative Instruments (continued)

result of the ongoing litigation regarding this matter, the termination invoice amount was recognized net of appropriate reserves, as an offsetting gain to Other Income/(Expense) and as a long term receivable of $72.5 million in Other Deferred Charges (see Note 12).

During 2001, Transmission entered into an interest rate swap transaction to hedge the fair value risk associated with $135 million of existing long-term fixed rate debt. This transaction qualified and was accounted for as a fair value hedge in accordance with SFAS No. 133. Fair value recognition of this hedging instrument resulted in $3.2 million being recorded to price risk management liabilities and as an offset to long-term debt at December 31, 2001. This instrument was terminated in May 2002 with a fair value loss of $2.6 million being recorded in long term debt, which is being amortized over the life of the debt issued as an adjustment to interest expense.

During 2002, Transmission initiated a new swap to hedge interest rate changes which could occur between the initiation date of the swap and the issuance date of the July 2002 $250 million note offering. The aggregate notional amount of this swap was $250 million. This swap was terminated effective July 18, 2002. The $12.3 million fair value loss at the termination of the swap agreement was recognized as other comprehensive loss and is being amortized over the life of the related debt issue as an adjustment to interest expense.

(5) Income Taxes

The principal components of the Company's net deferred income tax liabilities at December 31, 2003, and 2002 are as follows (in thousands):

	2003	2002
Deferred income tax assets		
Alternative minimum tax credit	$ 9,003	$ 16,560
Regulatory and other reserves	4,593	165
Other	137	314
	13,733	17,039
Deferred income tax liabilities		
Depreciation and amortization	658,501	624,793
Price risk management activities	16,565	22,739
Regulatory costs	11,052	9,065
Other	3,956	12,512
	690,074	669,109
Net deferred income tax liabilities	$ 676,341	$ 652,070

(5) Income Taxes (continued)

Total income tax expense for the years ended December 31, 2003, 2002 and 2001 is summarized as follows (in thousands):

	2003	2002	2001
Current Tax Provision (Benefit)			
Federal	$ 19,215	$ 4,996	$ 14,316
State	5,068	(1,422)	2,883
	24,283	3,574	17,199
Current Tax Provision (Benefit)			
Federal	21,930	47,101	29,160
State	2,341	9,053	4,376
	24,271	56,154	33,536
Total income tax expense	$ 48,554	$ 59,728	$ 50,735

The differences between taxes computed at the U.S. federal statutory rate of 35% and the Company's effective tax rate for the years ended December 31, 2003, 2002, and 2001 are as follows (in thousands):

	2003	2002	2001
Statutory federal income tax provision	$ 43,670	$ 54,709	$ 45,872
State income taxes, net of federal benefit	4,816	4,960	4,719
Other	68	59	144
Income tax expense	$ 48,554	$ 59,728	$ 50,735
Effective Tax Rate	38.9%	38.2%	38.7%

The Company has an alternative minimum tax (AMT) credit which can be used to offset regular income taxes payable in future years. The AMT credit has an indefinite carry-forward period. For financial statement purposes, the Company has recognized the benefit of the AMT credit carry-forward as a reduction of deferred tax liabilities.

The Company files a consolidated federal income tax return separate from its parents.

(6) Employee Benefit Plans

The employees of the Company are covered under Enron's employee benefit plans. Enron maintains the Enron Corp. Cash Balance Plan ("Plan"), which is a noncontributory defined benefit pension plan to provide retirement income for employees of Enron and its subsidiaries. Through December 31, 1994, participants in the Enron Corp. Retirement Plan with five years or more of service were entitled to retirement benefits in the form of an annuity based on a formula that used a percentage of final average pay and years of service. In 1995, Enron's Board of Directors adopted an amendment to and restatement of the Retirement Plan, changing the plan's name from the Enron Corp. Retirement Plan to the Enron Corp. Cash Balance Plan. In connection with a change to the retirement benefit formula, all employees became fully vested in retirement benefits earned through December 31, 1994. The formula in place prior to January 1, 1995 was suspended and replaced with a benefit accrual in the form of a cash balance of 5% of eligible annual base pay beginning on

(6) Employee Benefit Plans (continued)

January 1, 1996. Pension expenses charged to the Company by Enron were $1.9, $1.7, and $.7 million for 2003, 2002, and 2001, respectively.

Enron initiated steps to terminate the Cash Balance Plan in 2003. Effective January 1, 2003, Enron suspended the 5% benefit accruals under the Cash Balance Plan. Each employee's accrued benefit will continue to be credited with interest based on ten-year Treasury Bond yields. Because the Company is not part of an Enron "controlled group," as provided by Section 414(b) and (c) of the Internal Revenue Code of 1986, as amended, if the Plan were to be terminated or if the Company were to withdraw from participation in the Plan, the Company would be liable for only its proportionate share of any under-funding that may exist in the Plan at the time of such termination or withdrawal. On December 31, 2003, Enron Corp filed a motion with the Bankruptcy Court seeking authorization to contribute up to $200 million to fully fund and terminate the Cash Balance Plan and other pension plans of related debtor companies and affiliates. The Bankruptcy Court approved the motion on January 29, 2004. On February 5, 2004, Enron's Board of Directors voted to amend and terminate the Enron Corp. Cash Balance Plan. The Cash Balance Plan's official termination date is currently set for May 31, 2004. Before the Plan can be terminated, Enron must comply with certain federal regulatory requirements, including filing for necessary approvals and notifying Cash Balance Plan participants of the Plan termination at least 60 days prior to the termination date. Both the Pension Benefit Guaranty Corporation ("PBGC") and the Internal Revenue Service ("IRS") must approve the termination of the Plan (the IRS needs to determine that the Plan is tax-qualified as of the date of termination). In 2003, the Company recognized its portion of the expected Cash Balance Plan settlement by recording a $9.6 million current liability, and a charge to operating expense. The Company will seek to recover this expense from its customers through the pending rate case proceeding. Several creditors, including the PBGC, have filed objections to Enron's Chapter 11 Plan. The PBGC is arguing that $200 million may be insufficient to fund the plans filed for termination in Enron's December 31, 2003, motion with the Bankruptcy Court. The Bankruptcy Court has scheduled a hearing for April 20, 2004, on the Chapter 11 Plan. Based on the current status of the Cash Balance Plan settlement and the amount expected to be allocated to the Company as its proportionate share of the plan's termination liability, the Company believes this accrual is adequate but not excessive. Although there can be no assurance that amounts ultimately allocated to and paid by the Company will not be materially different, we do not believe that the ultimate resolution of this matter will have a materially adverse effect on the Company's consolidated financial position or cash flows, but it could have significant impact on the results of operations in future periods.

Enron provides certain post-retirement medical, life insurance and dental benefits to eligible employees and their eligible dependents. The net periodic post-retirement benefit costs charged to the Company by Enron were $1.2, $1.3, and $1.2 million for 2003, 2002, and 2001, respectively. Substantially all of these relate to Transmission and are being recovered through rates.

Certain retirees of Transmission were covered under a deferred compensation plan managed and funded by Enron subsidiaries, one previously sold and the other now in bankruptcy. This matter has been included as part of the claim filed by Transmission in bankruptcy against Enron and other affiliated bankrupt companies. Transmission has not conceded that it has a legal responsibility to fund the obligations to these certain retirees, but has approved certain payments in the past in order to avoid litigation. If such obligation were deemed to be a liability to Transmission, the range of exposure is $0 to approximately $2.0 million. Transmission does not believe that the ultimate resolution of this matter will have a materially adverse effect on operating results, financial position or cash flow.

(7) Major Customers

Revenues from individual third party and affiliate customers exceeding 10% of total revenues for the years ended December 31, 2003, 2002, and 2001 were approximately as listed below (in millions). Due to the early adoption of SFAS No. 133, Trading's gas sales transactions for the period ended December 31, 2001 were not reported as revenues to the Company. All amounts had been reported net in Other Income (Expense). Beginning in 2002, the revenues and expenses are reported separately (see Note 4).

Customers	2003	2002	2001
Florida Power & Light Company	$ 186.6	$ 171.2	$ 144.2
Enron North America (affiliate)	0.0	0.3	346.8
El Paso Merchant Energy (affiliate)	14.5	60.9	18.1

At December 31, 2003, and 2002, the Company had receivables of approximately $15.1 and $15.4 million from Florida Power & Light Company. At December 31, 2003, and 2002, the Company had a prepayment of approximately $0.4 and a receivable of approximately $7.8 million from El Paso Merchant Energy.

(8) Related Party Transactions

In December 2001, Enron and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court. The Company was not included in the bankruptcy filing, and Management believes that the Company will continue to be able to meet its own operational and administrative service obligations.

The Company incurs certain corporate administrative expenses from Enron and its affiliates. These services include administrative, legal, compliance, and pipeline operations emergency services. The arrangement was historically governed by the provisions of an operating agreement between an Enron affiliate and the Company which expired on June 30, 2001, and which has not been extended. However, Enron subsidiaries have continued to provide services under the terms of the original operating agreement. The Company reimburses the Enron subsidiaries for costs attributable to the operations of the Company. The Company expensed approximately $13.0, $14.9, and $13.8 million for these charges for the years ended December 31, 2003, 2002, and 2001, respectively.

Services provided by bankrupt Enron affiliates are allocated to the Company pursuant to a Bankruptcy Court ordered allocation methodology. Under that methodology the Company is obligated to pay allocated amounts, subject to certain terms and conditions. Consistent with these terms and conditions, the Company accrues and pays the full amount for services it receives directly from the bankrupt Enron affiliates. Indirect Enron service allocations are capped commensurate with 2001 levels. In 2002, the Company was allocated $32.7 million, of which it paid $2.1 million for indirect services and $10.7 million for direct services. Enron accepted this settlement in 2003. In 2003, the Company accrued $2.1 million for indirect services and $9.4 million for direct services, and has paid a total of $10.1 million, of which $7.5 million was paid as of December 31, 2003. Final 2003 allocations will not be completed until mid-2004; however, the Company believes its 2003 accruals reflect reasonable estimates of services received.

The Company provides natural gas sales and transportation services to Enron and El Paso affiliates at rates equal to rates charged to non-affiliated customers in the same class of service. Revenues related to these transportation services were approximately $0.0, $0.4, and $3.4 million from Enron affiliates and $5.3, $5.7, and $3.6 million from El Paso affiliates for the years ended December 31, 2003, 2002, and 2001, respectively. The Company's gas sales were approximately

(8) Related Party Transactions (continued)

$0.0, $0.0, and $343.7 million to Enron affiliates and $9.2, $55.2, and $14.5 million to El Paso affiliates for the years ended December 31, 2003, 2002, and 2001, respectively. The Company also purchased gas from affiliates of Enron of approximately $3.7, $0.0, and $216.9 million and from affiliates of El Paso of approximately $26.9, $19.9, and $100.5 million for the years ended December 31, 2003, 2002, and 2001, respectively. Transmission also purchased transportation services from Southern in connection with its Phase III Expansion completed in early 1995. Transmission contracted for firm capacity of 100,000 Mcf/day on Southern's system for a primary term of 10 years, to be continued for successive terms of one year each thereafter unless cancelled by either party, by giving 180 days notice to the other party prior to the end of the primary term or any yearly extensions thereof. The amount expensed for these services totaled $6.6, $6.9, and $6.7 million for the years ended December 31, 2003, 2002, and 2001, respectively.

Effective the fourth quarter of 1997, the operations of the contracts held by Trading were divided between affiliates of Enron and El Paso. The fee charged, for services such as scheduling, billing, and other back office support, is based on a volumetric payment of $.005/MMBtu, or approximately 50% of the prior arrangement. During 2003, Trading accrued and paid $0.015 million to El Paso Merchant Energy and accrued $0.079, and paid $0.243 million, (for all post-petition items) to ENA, for administrative fees. Under this agreement, Trading was guaranteed an earnings stream based on all firm long-term contracts in place at November 1, 1997. The earnings stream now fluctuates due to the variable pricing currently in effect, the result of ENA rejecting all aspects of certain agreements in bankruptcy proceedings. As of September 8, 2003, Trading assumed operating responsibilities relating to the securing of all supply not provided by El Paso Merchant Energy and scheduling of volumes. See Note 4 for additional details.

The Company either jointly owns or licenses with other Enron affiliates certain computer and telecommunications equipment and software that is critical to the conduct of its business. In other cases, such equipment or software is wholly-owned by such affiliates, and the Company has no ownership interest or license in or to such equipment or software. Transmission participated in business applications that are shared among the Enron pipelines. All participating pipelines use the same common base system and also have a custom pipeline-specific component. Each pipeline pays for its custom development component and shares in the common base system development costs. There are specific software licenses that were entered into by an Enron affiliate that entitle Transmission to usage of the software licenses. Fees for this arrangement are included in the amounts paid for corporate administrative expenses.

Transmission is a party to a Participation Agreement, dated effective as of November 1, 2002, with Enron and Enron Net Works to provide Electronic Data Interchange (EDI) services through an outsourcing arrangement with EC Outlook. Enron renegotiated an existing agreement with EC Outlook that lowered the cost of EDI services and that also provided the means for Transmission to be compliant with the most recent North American Energy Standards Board (NAESB) EDI standards. The contract has a termination date of November 30, 2005. Fees for this arrangement are included in the amounts paid for corporate administrative expenses.

Transmission has a construction reimbursement agreement with ENA under which amounts owed to Transmission are delinquent. These obligations (including post-petition interest which cannot be collected) total approximately $7.4 million and are included in Transmission's filed bankruptcy claims. These receivables were fully reserved by Transmission prior to 2003. Transmission has also filed proofs of claims regarding other claims against ENA in the bankruptcy proceeding (see Note 14). In its rate case filed with the FERC (see Note 10), Transmission has proposed to recover the estimated under-recovery on this obligation by rolling in the costs of the facilities

(8) Related Party Transactions (continued)

constructed, less the estimated recovery from ENA, into its rates. However, Transmission cannot predict the amounts, if any, that it will collect or the timing of collection.

In addition to the above Transmission claim against ENA, Trading has filed proofs of claims against ENA totaling $152.3 million for commodity and financial transactions operable prior to ENA's bankruptcy. Recovery of certain of these claimed amounts is interrelated with Trading's gas purchase counterparty litigation and associated Other Deferred Charge (see Notes 4 and 14).

Transmission entered into a 20-year compression service agreement with Enron Compression Services Company (ECS) in April 2002. This agreement requires Transmission to pay ECS to provide electric horsepower capacity and related horsepower hours to be used to operate Compressor Station No. 13A, which consists of an electric compressor unit. Amounts paid to ECS in 2003 and 2002 totaled $2.3 and $1.5 million respectively. Under related agreements, ECS is required to pay Transmission an annual lease fee and a monthly operating and maintenance fee to operate and maintain the facilities. Amounts received from ECS in 2003 and 2002 for these services were $0.4 and $0.3 million, respectively. A Netting Agreement, dated effective November 1, 2002, was executed with ECS, providing for the netting of payments due under each of the O&M, lease, and compression service agreements with ECS.

(9) Cash Flow Statement Reclassification

During 2000, Trading entered into a commodity transaction with an Enron affiliate as follows. Trading entered into three agreements, each dated December 1, 2000. Under the first agreement, Trading contracted to purchase approximately 12 million MMBtu of gas from an Enron affiliate at $6.65 per MMBtu with payment due by Trading in December 2000. In the second agreement, Trading contracted to sell 12 million MMBtu of gas to the same Enron affiliate in December 2000 at $6.67536 per MMBtu, with payment due from the Enron affiliate in January 2001. In the third agreement, Trading and the same Enron affiliate exchanged the two 12 million MMBtu gas delivery obligations under the prior two agreements; Trading was paid an exchange fee of $0.01051 per MMBtu. This third agreement had the effect of canceling obligations for physical delivery of gas by Trading and the Enron affiliate to each other under the prior two agreements, with only the financial obligations remaining. As a result of these related transactions, Trading paid the Enron affiliate approximately $80 million in December 2000 and received approximately $80.4 million in January 2001. In addition, in December 2000 Trading agreed to pay the same Enron affiliate approximately $20 million in December instead of January 2001 on an existing gas contract for which Trading was paid a fee for this early payment. This fee was included in the total cost of funds to Trading (both for the $80 million arrangement and the $20 million early payment) that was recovered through the margin the Enron affiliate agreed to pay Trading under the second agreement and the exchange fee the Enron affiliate agreed to pay Trading under the third agreement described above. Trading's favorable cash flow variance in 2001 resulting from these transactions with the Enron affiliate was partially offset by higher interest payments and increased income tax payments in 2001.

In conjunction with the 2003 development and filing of the Enron bankruptcy plan of reorganization, Enron evaluated selected affiliate transactions, including the $80 million gas sales, purchase and exchange agreements between Trading and an Enron affiliate during December 2000 and January 2001, discussed above. The Company originally reflected the transactions as operating cash flows. Based on an analysis of all available information from both Trading and Enron, the Company determined the transactions were in substance a financing for the benefit of the Enron affiliate and has reclassified the cash flows from operations to financing.

(10) Regulatory Matters

Transmission's currently effective rates were established pursuant to a Stipulation and Agreement (Rate Case Settlement) which resolved all issues in Transmission's Natural Gas Act (NGA) Section 4 rate filing in FERC Docket No. RP96-366. The Rate Case Settlement, approved by FERC Order issued September 24, 1997, provided that Transmission could not file a general rate case to increase its base tariff rates prior to October 1, 2000 (except in certain limited circumstances) and must file no later than October 1, 2001, since extended to October 1, 2003 pursuant to the Phase IV settlement discussed below. The Rate Case Settlement also provided that the rates charged pursuant to Transmission's Firm Transportation Service (FTS) rate schedule FTS-2 would decrease effective March 1, 1999 and March 1, 2000.

On October 1, 2003, Transmission filed a general rate case, proposing rate increases for all services, based upon a cost of service of approximately $165 million for the pre-expansion system and approximately $342 million for the incremental system. Based on Test Period reservation and usage determinants, the proposed rate increase under all Rate Schedules, ignoring the impact of existing rate caps, negotiated rates, and discounts, would generate approximately $56 million in additional annual transportation revenues for Transmission. The overall return requested is 11.81%, reflecting an 8.64% cost of debt and a 14.50% return on common equity, and is based on a capital structure of 45.92% debt and 54.08% equity. The cost of service for the pre-expansion system includes an increase in the depreciation rate applicable to onshore facilities, from 2.13% to 3.00%. In addition, Transmission has proposed certain revisions to various rate schedules. Other prospective changes proposed include the change to a traditional cost-of-service rate design (with straight-line depreciation, as opposed to variable depreciation under the currently-effective levelized rates) for the expansion system, a tracker for certain types of significant capital costs, and compliance with Order No. 637. A number of parties protested the rates. By order dated October 31, 2003, FERC suspended the proposed rates for five months (until April 1, 2004); set the tariff revisions limiting rights to convert FTS-1 service to Small Firm Transportation Services (SFTS), and setting a minimum volume for No Notice Transportation Service (NNTS) service for a technical conference; set all other issues for hearing; accepted the tariff change with regard to limiting reservation charge credits but only in cases of force majeure events (thus, in force majeure events, Transmission would only be required to refund to customers the return and related income tax components of its rates). Transmission made the required compliance filing and several customers protested, to which Transmission filed an answer in opposition. FERC staff has issued its initial position on a number of issues. At a technical conference held on January 7, 2004, Transmission agreed to withdraw its NNTS minimum volume proposal, subject to certain customers withdrawing their nominations. An initial settlement conference was held on March 11, 2004; the next settlement conference is set for March 30. In the event a settlement is not achieved, the hearing is set for August 31, 2004.

On December 1, 1998, Transmission filed an NGA Section 7 certificate application with the FERC in Docket No. CP99-94-000 to construct 205 miles of pipeline in order to extend the pipeline to Ft. Myers, Florida and to expand capacity by 272,000 MMBtu/day (Phase IV Expansion). Expansion costs were estimated at $351 million. Transmission requested that expansion costs be rolled into the rates applicable to FTS-2 (Incremental) service. On June 2, 1999, Transmission filed a Stipulation and Agreement (Phase IV Settlement) which resolved all non-environmental issues raised in the certificate proceeding and modified the Rate Case Settlement to provide that Transmission cannot file a general rate case to increase its base tariff rates prior to October 1, 2001 (except in certain limited circumstances), and must file no later than October 1, 2003. The Phase IV Settlement was approved by the FERC by order issued July 30, 1999, and became effective thirty days after the date that Transmission accepted an order issued by the FERC approving the Phase IV Expansion project. On August 23, 1999, Transmission amended its application on file with the

(10) Regulatory Matters (continued)

FERC to eliminate a portion of the proposed facilities (that would be delayed until the Phase V Expansion). The amended application reflected the construction of 139.5 miles of pipeline and an expansion of capacity in order to provide incremental firm service of 196,405 MMBtu on an average annual day, with estimated project costs of $262 million. The Phase IV Expansion was approved by FERC order issued February 28, 2000, and accepted by Transmission on March 29, 2000. The Phase IV Expansion was placed in service on April 30, 2001. Total costs through December 31, 2003, were $246 million.

On December 1, 1999, Transmission filed an NGA Section 7 certificate application with the FERC in Docket No. CP00-40-000 to construct 215 miles of pipeline and 90,000 horsepower of compression and to acquire an undivided interest in the existing Mobile Bay Lateral owned by Koch Gateway Pipeline Company (now Gulf South Pipeline Company, LP), in order to expand the system capacity to provide incremental firm service to several new and existing customers of 270,000 MMBtu on an average annual day (Phase V Expansion). Expansion and acquisition costs were estimated at $437 million. Transmission requested that expansion costs be rolled into the rates applicable to FTS-2 (Incremental) service. On August 1, 2000, and September 29, 2000, Transmission amended its application on file with the FERC to reflect the withdrawal of two customers, the addition of a new customer and to modify the facilities to be constructed. The amended application reflected the construction of 167 miles of pipeline and 133,000 horsepower of compression to create additional capacity to provide 306,000 MMBtu of incremental firm service on an average annual day. The estimated cost of the revised project is $462 million. The Phase V Expansion was approved by FERC Order issued July 27, 2001, and accepted by Transmission on August 7, 2001. Segments of the Phase V Expansion project were placed in service in December 2001, March 2002, and April 2003, respectively. Total costs through December 31, 2003, were $417 million.

On November 15, 2001, Transmission filed an NGA Section 7 certificate application with the FERC in Docket No. CP02-27-000 to construct 33 miles of pipeline and 18,600 horsepower of compression in order to expand the system to provide incremental firm service to several new and existing customers of 85,000 MMBtu on an average day (Phase VI Expansion). Expansion costs were estimated at $105 million. Transmission requested the expansion costs be rolled into rates applicable to FTS-2 (Incremental) service. The application was approved by FERC Order issued on June 13, 2002, and accepted by Transmission on July 19, 2002. Clarification was granted and a rehearing request of a landowner was denied by FERC Order of September 3, 2002. The Phase VI Expansion was completed and placed in service during 2003 with the exception of the compressor station modifications at stations 12, 15, and 24. Compressor station modifications at stations 12 and 24 were completed and placed in-service on January 31, 2004, and February 1, 2004, respectively. Modifications at compressor station 15 are scheduled to be completed by April 15, 2004. Total costs through December 31, 2003, were $73 million.

In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. On July 25, 2003, the FERC issued its "Modification of Negotiated Rate Policy", in which it determined that it "will no longer permit the use of gas basis differentials to price negotiated rate transactions." On August 25, 2003, the Interstate Natural Gas Association of America (INGAA) filed a request for rehearing of this ruling. On September 12, 2003, the Commission issued an order granting rehearing for the purposes of further consideration, thus, tolling the statutory time in which the FERC is required to act. On December 18, 2003, the Commission issued orders in two cases, essentially reversing this ruling for rates that will remain between the minimum and maximum tariff rates. Transmission has only two negotiated rate agreements, and both of these are at or below Transmission's currently effective maximum tariff rates as well as the proposed rates in the 2003 rate case (see note on rate

(10) Regulatory Matters (continued)

case above). Thus, Transmission does not anticipate its negotiated rate transactions being impacted by this rulemaking. At this time, Transmission cannot predict the outcome of this NOI.

On August 1, 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent maintain investment grade credit ratings. The FERC held a public conference on September 25, 2002, to discuss the issues raised in comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. On June 26, 2003, the FERC issued an Interim Rule requiring that cash management agreement be in writing, specify the duties and responsibilities of the participants, specify the methods for calculating interest and for allocating interest income and expenses, and specify any restriction on deposits or borrowing by participants. Since Transmission does not participate in a cash management pool, Transmission does not anticipate that this rule will have an impact. The Interim Rule also required that pipelines notify the FERC when their proprietary capital ratio drops below 30 percent. In addition, in the Interim Rule the FERC sought further comments on these requirements. On October 23, 2003, the FERC issued its Final Rule, which adopted the requirement of the Interim Rule to file cash management agreements with the FERC. The Final Rule also required that pipelines must notify the FERC within 45 days after the end of each calendar quarter if their proprietary capital ratios drop below or subsequently exceed 30 percent. In its Final Rule requiring quarterly financial reporting, issued February 11, 2004, the FERC lifted the requirement to notify the FERC when proprietary capital drops below or rises above 30 percent.

In 2002, Transmission was subject to an industry wide nonpublic investigation of the FERC Form 2 (FERC's annual report) focusing on cash management or transfers between Transmission and Enron or affiliated companies. By order issued September 8, 2003, the FERC determined that Transmission was generally in compliance. However, the FERC found that because Transmission was in a cash management pool during the time of the audit and because best management practices require a written cash management plan, Transmission ought to have a written cash management plan. On October 8, 2003, Transmission sought clarification or, in the alternative, rehearing of the order that Transmission did not have to have a written cash management plan at this time because Transmission was not now participating in a cash management pool. On December 4, 2003, the FERC issued an order granting Transmission's request for clarification.

In April 2002, FERC and the Department of Transportation, Office of Pipeline Safety convened a technical conference to discuss how to clarify, expedite, and streamline permitting and approvals for interstate pipeline reconstruction in the event of a natural or other disaster. On January 17, 2003, FERC issued a NOPR proposing to (1) expand the scope of construction activities authorized under a pipeline's blanket certificate to allow replacement of mainline facilities; (2) authorize a pipeline to commence reconstruction of the affected system without a waiting period; and (3) authorize automatic approval of construction that would be above the normal cost ceiling. Comments on the NOPR were filed by INGAA on February 27, 2003. On May 19, 2003 the FERC issued Order

(10) Regulatory Matters (continued)

No. 633, promulgating a final rule that allows pipelines to start construction to replace mainline facilities without the normal 45-day notice period when immediate action is required to restore service. This rule will impact Transmission only in the event of an emergency action. In such event, Transmission expects that the rule would expedite replacement or repair of facilities, thereby reducing any service interruption period.

On November 25, 2003, the FERC issued Order No. 2004 making significant changes in the Standards of Conduct ("SOC") governing the relationships between pipelines and Energy Affiliates. The new SOC applies to a greater number of affiliates, requires more reporting, and requires appointment of a compliance officer. On December 24, 2003, INGAA filed a request for rehearing. On January 20, 2004, the Commission issued an order granting rehearing for the purposes of further consideration, thus, tolling the statutory time in which the FERC is required to act. At this time, Transmission cannot predict the final outcome of the proceeding. On February 9, 2004, Transmission made the required informational filing with regard to compliance by June 1. Certain companies plan to seek delay of the implementation to September 2004, in view of the number of pending rehearing and clarification requests. Transmission believes that the ultimate outcome of this matter will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flow.

On December 15, 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulation defines as "high consequence areas" ("HCA"). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a bill signed into law on December 17, 2002. The rule requires operators to identify HCAs along their pipelines by December 2004, to have begun baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing, or direct assessment, by June 2004. Operators must risk rank their pipeline segments containing HCAs, and have the highest 50% assessed using one or more of these methods by December 2007. The balance must be completed by December 2012. The costs of utilizing these methods typically range from a few thousand dollars per mile to well over $15,000 per mile. In addition, some system modifications will be necessary to accommodate the inspections. Because identification and location of all the HCAs has not been completed, and because it is impossible to determine the scope of required remediation activities prior to completion of the assessments and inspections, the cost of implementing the requirements of this regulation is impossible to determine at this time. The required modifications and inspections are estimated to range from approximately $12-15 million per year, with remediation costs in addition to these amounts.

On December 29, 2003, the Securities and Exchange Commission ("SEC") denied Enron's outstanding applications for exemption under the Public Utility Holding Company Act of 1935 ("PUHCA"). Enron applied for an additional exemption on December 31, 2003. Under PUHCA, the Company would be a subsidiary of a holding company, but could be eligible for certain exemptions if such exemptions were applied for by Enron and approved by the SEC (see Note 18).

(11) Property, Plant and Equipment

The principal components of the Company's Property, Plant and Equipment at December 31, 2003, and 2002 are as follows (in thousands):

	2003	2002
Transmission Plant	$ 2,725,065	$ 2,427,851
General Plant	25,619	37,041
Intangible Plant	20,612	20,446
Construction Work-in-progress	35,638	176,484
Acquisition Adjustment	1,252,466	1,252,466
	4,059,400	3,914,288
Less: Accumulated depreciation and amortization	(1,072,072)	(1,004,345)
Net Property, Plant and Equipment	$ 2,987,328	$ 2,909,943

(12) Other Deferred Charges

The principal components of the Company's other deferred charges at December 31, 2003, and 2002 are as follows (in thousands):

	2003	2002
Ramp-up assets, net *(1)*	$ 12,552	$ 12,073
Fuel tracker	6,479	2,278
Long-term receivables	77,080	5,256
Overhauls, net of current amortization (see Note 2)	—	5,376
Cash collateral (see Note 3) *(2)*	595	16,373
Receipts for escrow	7,700	7,700
Balancing tools *(3)*	834	2,203
Other miscellaneous	3,140	3,359
Total Other Deferred Charges	$ 108,380	$ 54,618

(1) "Ramp-up" assets is a regulatory asset Transmission was specifically allowed in the FERC certificates authorizing the Phase IV and V Expansion projects.

(2) Collateral posted to another party remains the property of the posting party, unless it defaults on the collateralized obligation.

(3) Balancing tools are a regulatory method by which Transmission recovers the costs of operational balancing of the pipelines' system. The balance can be a deferred charge or credit, depending on timing, rate changes, and operational activities.

(13) Other Deferred Credits

The principal components of the Company's other deferred credits at December 31, 2003, and 2002 are as follows (in thousands):

	2003	2002
Accrued expansion post construction mediation costs *(1)*	$ 4,131	$ —
Customer deposits (see Note 15)	8,859	8,205
Phase IV retainage & Phase V surety bond	471	1,644
Miscellaneous	157	196
Total Other Deferred Credits	$ 13,618	$ 10,045

(1) Related to significant Phase IV, V, and VI expansion projects

(14) Commitments and Contingencies

From time to time, in the normal course of business, the Company is involved in litigation, claims or assessments that may result in future economic detriment. The Company evaluates each of these matters and determines if loss accruals are necessary as required by SFAS No. 5, *Accounting for Contingencies.* The Company does not expect to experience losses that would be materially in excess of the amount accrued at December 31, 2003.

Transmission and Trading have filed bankruptcy related claims against Enron and other affiliated bankrupt companies totaling $220.6 million. Transmission's claim includes rejection damages and delinquent amounts owed under certain transportation agreements, an unpaid promissory note, and other fees for services and imbalances. Subsequent to Transmission's filing its claims, ENA's firm transportation agreements were permanently relinquished to a creditworthy party, which significantly reduced Transmission's rejection damages. Trading's claim is for rejection damages on two physical/financial swaps, a gas sales contract, and on the Operating Agreement, as well as certain delinquent amounts owed pre-petition. In July, one Enron affiliate, ENA, indicated that it did not agree with the amount of the claims and wanted to discuss settlement/resolution. Discussion of possible settlement is underway.

On March 7, 2003, Trading filed a declaratory order action, involving a contract between it and Duke. Trading requested that the court declare that Duke breached the parties' natural gas purchase contract by failing to provide sufficient volumes of gas to Trading. The suit seeks damages and a judicial determination that Duke has not suffered a "loss of supply" under the parties' contract, which could, if it continued, have given rise to the right of Duke to terminate the contract at a point in the future. On April 14, 2003, Duke sent Trading a notice that the contract was terminated as of April 16, 2003 (due to Trading's alleged failure to timely increase the amount of a letter of credit); although it disagreed with Duke's position, Trading increased the letter of credit on April 15. Duke has answered and filed a counterclaim, arguing that Trading failed to timely increase the amount of a letter of credit, and that it has breached a "resale restriction" on the gas. Trading disputes that it has breached the agreement, or that any event has given rise to a right to terminate by Duke. On April 29, 2003, Duke filed to remove the case to federal court (CA03-CV-1425). On May 1, 2003, Trading notified Duke that it was in default under the Agreement, for failure to deliver the base volumes beginning April 17. However, Duke continued to refuse to perform under the contract. On May 28, 2003, Trading filed a motion to remand the case to state court. On June 2, 2003, Trading notified Duke that, because Duke had not cured its default, Trading terminated the agreement effective as of June 5, 2003. On August 8, 2003, Trading sent its final "termination payment" invoice to Duke in the amount of $187 million. On July 31, 2003, the federal court granted Trading's motion

(14) Commitments and Contingencies (continued)

and remanded the case to state court. On August 18, 2003, Duke filed a Third-Party Petition against Sonatrading and Sonatrach, its Algerian suppliers (''Sonatrach''), which Trading opposed since, *inter alia,* even in the event of a failure to receive supplies from Algeria, Duke was required to furnish supplies to Trading for a stated period of time. On October 6, Trading filed its Amended Petition, alleging wrongful termination and containing the termination damages. In October, Sonatrach removed the case to federal court and filed a special appearance challenging jurisdiction. On November 25, 2003, Trading filed its Second Amended Complaint, alleging, among other things, that Duke was required to give reasonable notice to Trading to upgrade the letter of credit, before terminating the contract. On December 5, Duke filed its answer. Sonatrach's motion to dismiss for lack of jurisdiction was filed March 2, and Duke's response is due by March 31, 2004. Discovery is ongoing, and the judge continues to hold informal discovery in an attempt to resolve the case. On March 8, Trading made demand on PanEnergy, who, along with Duke is a signatory to the agreement, asking for PanEnergy to ensure (per the contracts) that Duke has sufficient assets to pay Trading's claim. Because assurances were not forthcoming, on March 16, 2004, Trading filed suit against PanEnergy in state court. On March 23, 2004, Trading filed a motion for Summary Judgment against Duke, seeking a ruling that Duke was required to provide Trading with notice before terminating the agreements. This is a disputed matter, and there can be no assurance as to what amounts, if any, Trading will ultimately recover. Management believe that the amount ultimately recovered will not be materially different than the amount recognized at December 31, 2003, and that the ultimate resolution of this matter will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows. Management further believes that claims made by Duke against the Company with regard to this matter are without merit and do not constitute a liability which would require adjustment to or disclosure in the Company's December 31, 2003, consolidated financial statements in accordance with SFAS No. 5, *Accounting for Contingencies.*

In 1999, Transmission entered into an agreement which obligated it to various natural gas and construction projects includable in its rate base. This obligation ends July 1, 2004, and Transmission expects to incur an additional $1.1 million of potentially capitalizable costs prior to contract expiration.

The Florida Turnpike Authority (FTA) has several turnpike widening projects in the planning stage, which may, over the next ten years, impact one or more of Transmission's mainlines co-located in FTA right-of-way. The most immediate projects are five Sunshine State Parkway projects, which are proposed to overlap Transmission's pipelines, for a total of approximately 22 miles. Under certain conditions, the existing agreement between Transmission and the FTA calls for the FTA to pay for any new right-of-way needed for the relocation projects and for Transmission to pay for construction costs. The actual amount of miles of pipe to be impacted ultimately, and the relocation cost and/or right-of-way cost, recoverable through rates, is either undefined at this time, due to the preliminary stage of FTA's planning process, or the FTA has determined not to require Transmission to relocate its line. No preliminary estimate of the cost associated with this potential relocation has been calculated, and it is not estimable at this time.

(15) Concentrations of Credit Risk and Other Financial Instruments

The Company has a concentration of customers in the electric and gas utility industries. These concentrations of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. Credit losses incurred on receivables in these industries compare favorably to losses experienced in the Company's receivable portfolio as a whole. The Company also has a concentra-

(15) Concentrations of Credit Risk and Other Financial Instruments (continued)

tion of customers located in the southeastern United States, primarily within the state of Florida. Receivables are generally not collateralized. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments, deposits, or other forms of security to the Company. Transmission sought additional assurances from customers due to credit concerns, and had customer deposits totaling $8.9 million and $8.2 million and prepayments of $1.6 million and $2.9 million for 2003 and 2002, respectively. The Company's management believes that the portfolio of Transmission's receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is of minimal credit risk.

The carrying amounts and fair value of the Company's financial instruments at December 31, 2003, and 2002 are as follows (in thousands):

	2003		2002	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Cash and cash equivalents	$ 125,226	$ 125,226	$ 114,682	$ 114,682
Long-term debt	1,167,500	1,396,453	1,252,750	1,398,291

The carrying amount of cash and cash equivalents reasonably approximate their fair value. The fair value of long-term debt is based upon market quotations of similar debt at interest rates currently available.

(16) Comprehensive Income

Comprehensive income includes the following (in thousands):

	2003	2002	2001
Net income	$ 76,216	$ 96,587	$ 80,328
Other comprehensive income:			
Derivative instruments:			
Deferred loss on anticipatory cash flow hedge (see note 4)	—	(12,280)	—
Recognition in earnings of previously deferred (gains) and losses related to derivative instruments used as cash flow hedges	1,206	540	(21)
Total comprehensive income	$ 77,422	$ 84,847	$ 80,307

(17) Accounting Pronouncements

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement requires companies to record a liability for the estimated removal costs of assets used in their business where there is a legal obligation associated with removal. The liability is recorded at its fair value, with a corresponding asset that is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143, beginning January 1, 2003. A comprehensive study was made in 2003 by the Company's Accounting, Right of Way, Legal, Internal Audit, and Operations personnel to identify all Asset Retirement Obligations that are estimable as defined in

(17) Accounting Pronouncements (continued)

SFAS No. 143, and it has been determined that the adoption of this standard did not have a financial statement impact at this time. The Company will continue to monitor these requirements on an annual basis in future.

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require recognition of costs associated with exit or disposal activities when they are incurred rather than when a commitment is made to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. This statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities initiated after January 1, 2003. SFAS No. 146 has not had an impact on the Company's financial position or results of operations.

In November 2002, the FASB issued FIN No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Others.* This interpretation requires that companies record a liability for all guarantees issued or modified after December 31, 2002, including financial, performance, and fair value guarantees. This liability is recorded at its fair value upon issuance, and does not affect any existing guarantees issued before December 31, 2002. While FIN No. 45 has not had an impact on the Company's financial position or results of operations, it will impact any guarantees the Company issues in the future.

(18) Subsequent Events

On February 6, 2004, Enron filed two form U1's with the SEC, proposing a set of conditions under which Enron would register as a holding company under PUHCA. Among other things, Enron sought an exemption for the Company under Rule 16 of the SEC's PUHCA Rules and Regulations (17 CFR §250.16, "Exemption of Non-Utility Subsidiaries and Affiliates") (The "Exemption"). On March 9, 2004, Enron amended its form U1 application filings, withdrew its application for exemption filed on December 31, 2003, and filed a form U5A, registering as a public utility holding company under PUHCA. Also on March 9, 2004, the SEC issued orders approving the applications made on the amended form U1's and the U5A, including approval of the application for the Exemption. The result of these proceedings has reconfirmed the Company's exemptions.

On January 28, 2004, the Company extended the Waiver (see Note 3). However, due to the unresolved exemption status of Enron under PUHCA (see Note 10), Transmission agreed to further limit its rights under the Revolver by restricting its right to issue new letters of credit. At this time, Transmission cannot draw under the Revolver, nor can it issue new letters of credit.

SOUTHERN NATURAL GAS COMPANY

EXHIBIT LIST
December 31, 2003

Exhibits not incorporated by reference to a prior filing are designated by an asterisk. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
3.A	Restated Certificate of Incorporation dated as of March 7, 2002 (Exhibit 3.A to our 2001 Form 10-K).
3.B	By-laws dated as of June 24, 2002. (Exhibit 3.B to our 2002 Form 10-K).
4.A	Indenture dated June 1, 1987 between Southern Natural Gas Company and Wilmington Trust Company (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee; First Supplemental Indenture, dated as of September 30, 1997, between Southern Natural Gas Company and the Trustee; and Second Supplemental Indenture dated as of February 13, 2001, between Southern Natural Gas Company and the Trustee (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2001, File No. 333-76782).
4.B	Indenture dated as of March 5, 2003 between Southern Natural Gas Company and The Bank of New York, as Trustee (Exhibit 4.1 to our Form 8-K filed March 5, 2003).
10.A	$3,000,000,000 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN Amro Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.1 to El Paso Corporation's Form 8-K filed April 18, 2003.)
10.B	Security and Intercreditor Agreement dated as of April 16, 2003 among El Paso Corporation, the persons referred to therein as Pipeline Company Borrowers, the persons referred to therein as Grantors, each of the Representative Agents, JPMorgan Chase Bank, as Credit Agreement Administrative Agent and JPMorgan Chase Bank, as Collateral Agent, Intercreditor Agent, and Depository Bank. (Exhibit 99.3 to El Paso Corporation's Form 8-K filed April 18, 2003).
*21	Subsidiaries of Southern Natural Gas Company.
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.

Undertaking.

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission, upon request, all constituent instruments defining the rights of holders of our long-term debt and our consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

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 on the 30th day of March, 2004.

SOUTHERN NATURAL GAS COMPANY

By /s/ JOHN W. SOMERHALDER II

John W. Somerhalder II
Chairman of the Board

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

Signature	Title	Date
/s/ JOHN W. SOMERHALDER II (John W. Somerhalder II)	Chairman of the Board and Director (Principal Executive Officer)	March 30, 2004
/s/ JAMES C. YARDLEY (James C. Yardley)	President and Director	March 30, 2004
/s/ GREG G. GRUBER (Greg G. Gruber)	Senior Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial and Accounting Officer)	March 30, 2004