2002 Annual Report

ALABAMA POWER

A SOUTHERN COMPANY

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Alabama Power Company 2002 Annual Report

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SUMMARY

	2002	2001	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	$3,710	$3,586	3.5
Operating expenses	$2,688	$2,676	0.5
Net income after dividends on preferred stock	$461	$387	19.3
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	52,073	49,338	5.5
Sales for resale - non-affiliates	15,554	15,278	1.8
Sales for resale - affiliates	8,844	8,843	–
Total	76,471	73,459	4.1
Customers served at year-end *(in thousands)*	1,357	1,342	1.2
Peak-hour demand *(in megawatts)*	10,910	10,241	6.5
Capitalization Ratios *(percent)*:			
Common stock equity	49.8	42.9	
Preferred stock	3.7	4.1	
Company obligated mandatorily redeemable preferred securities	4.4	4.5	
Long-term debt (Excluding long-term debt due within one year)	42.1	48.5	
Return on Average Common Equity *(percent)*	13.80	11.89	

Alabama Power Company faced many challenges during 2002. In meeting these challenges, we once again lived up to our reputation and showed our strength and stability.

Our customers know they can count on Alabama Power Company to provide reliable service and low prices. Our shareholders know they can count on us to make every effort to meet our financial goals. Further, our communities know they can count on us to be environmentally responsible and to help make our state a better place to live for everyone.

Once again we met the expectations of our customers in 2002 by exceeding our previous service-reliability record and maintaining low prices. Thanks to our excellent transmission and distribution system, electric service was available to customers 99.96 percent of the time. Alabama Power Company again ranked in the top quartile in customer satisfaction in 2002, and our customers continued to pay prices that are 15% below the national average.

Alabama Power Company's commitment to our customers includes a desire to make the state a great place to live, work and do business. We are constantly researching and developing new ways to generate cleaner energy. We continue to be a leader in developing technology and taking the initiative to protect and clean up our environment.

We had a successful year and we believe the key to success will always be the same that is to make every decision with the best interest of your customer, shareholder and employee in mind and to take every action based upon the highest standards of ethics and integrity. Our business may change but these are beliefs you can count on always.

Solid values, a strong commitment to our customers and sound business strategies allowed us to successfully face the challenges of 2002 and they will allow us to move into the future in a position of strength.

Sincerely,

Charles D. McCrary
President and Chief Executive Officer
March 14, 2003

The management of Alabama Power Company has prepared -- and is responsible for -- the financial statements and related information included in this report. These statements were prepared in accordance with accounting principles generally accepted in the United States and necessarily include amounts that are based on the best estimates and judgments of management. Financial information throughout this annual report is consistent with the financial statements.

The Company maintains a system of internal accounting controls to provide reasonable assurance that assets are safeguarded and that the accounting records reflect only authorized transactions of the Company. Limitations exist in any system of internal controls, however, based on a recognition that the cost of the system should not exceed its benefits. The Company believes its system of internal accounting controls maintains an appropriate cost/benefit relationship.

The Company's system of internal accounting controls is evaluated on an ongoing basis by the Company's internal audit staff. The Company's independent public accountants also consider certain elements of the internal control system in order to determine their auditing procedures for the purpose of expressing an opinion on the financial statements.

The Southern Company audit committee of its board of directors, composed of five independent directors, provides a broad overview of management's financial reporting and control functions. Additionally, a committee of Alabama Power's board of directors, composed of three outside directors, meets periodically with management, the internal auditors and the independent public accountants to discuss auditing, internal controls, and compliance matters. The internal auditors and independent public accountants have access to the members of these committees at any time.

Management believes that its policies and procedures provide reasonable assurance that the Company's operations are conducted according to a high standard of business ethics.

In management's opinion, the financial statements present fairly, in all material respects, the financial position, results of operations and cash flows of Alabama Power Company in conformity with accounting principles generally accepted in the United States.

Charles D. McCrary
President
and Chief Executive Officer

William B. Hutchins, III
Executive Vice President,
Chief Financial Officer, and Treasurer

February 17, 2003

INDEPENDENT AUDITORS' REPORT

Alabama Power Company:

We have audited the accompanying balance sheet and statement of capitalization of Alabama Power Company (a wholly owned subsidiary of Southern Company) as of December 31, 2002, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for the year then ended. These financial statements are the responsibility of Alabama Power Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of Alabama Power Company as of December 31, 2001, and for each of the two years then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements and included an explanatory paragraph that described a change in the method of accounting for derivative instruments and hedging activities in their report dated February 13, 2002.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2002 financial statements (pages 18 to 39) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2002, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
February 17, 2003

THE FOLLOWING REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED IN CONNECTION WITH THE COMPANY'S 2001 ANNUAL REPORT AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

To Alabama Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (an Alabama corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2001 and 2000, and the related statements of income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2001. 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 management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements (pages 16-34) referred to above present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, Alabama Power Company changed its method of accounting for derivative instruments and hedging activities.

Arthur Andersen LLP

Birmingham, Alabama
February 13, 2002

RESULTS OF OPERATIONS

Earnings

Alabama Power Company's 2002 net income after dividends on preferred stock was $461 million, representing a $74 million (19.3 percent) increase from the prior year. This improvement is primarily attributable to increased territorial energy sales and higher retail rates when compared to the prior year. More favorable weather conditions in 2002 as compared to the unusually mild weather experienced in 2001 contributed to the increases in territorial sales. The increases in revenues were partially offset by increased non-fuel operating expenses.

In 2001 earnings were $387 million, representing a 7.9 percent decrease from the prior year. This decline was primarily attributable to a decrease in territorial energy sales as a result of an economic downturn and milder temperatures. Earnings in the year 2000 were $420 million, representing a 5 percent increase from the prior year. This improvement was primarily attributable to an increase in territorial sales partially offset by increased non-fuel operating expenses.

The return on average common equity for 2002 was 13.80 percent compared to 11.89 percent in 2001 and 13.58 percent in 2000. A condensed income statement is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2002	2002	2001	2000
	(in millions)			
Operating revenues	$3,710	$124	$(81)	$282
Fuel	970	(31)	38	108
Purchased power	249	(44)	(56)	75
Other operation and maintenance	854	71	(56)	30
Depreciation and amortization	398	15	19	17
Taxes other than income taxes	217	2	5	5
Total operating expenses	2,688	13	(50)	235
Operating income	1,022	111	(31)	47
Other income (expense), net	(269)	7	(15)	(8)
Less -- Income taxes	292	44	(13)	19
Net Income	$ 461	$ 74	$(33)	$ 20

Revenues

Operating revenues for 2002 were $3.7 billion, reflecting a $124 million increase from 2001. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2002	2001	2000
	(in thousands)		
Retail – prior year	$2,747,673	$2,952,707	$2,811,117
Change in -			
Base rates	76,326	22,918	-
Sales growth	70,050	(36,197)	58,347
Weather	60,089	(61,846)	21,917
Fuel cost recovery and other	(2,921)	(129,909)	61,326
Total retail	2,951,217	2,747,673	2,952,707
Sales for resale --			
Non-affiliates	474,291	485,974	461,730
Affiliates	188,163	245,189	166,219
Total sales for resale	662,453	731,163	627,949
Other operating revenues	96,862	107,554	86,805
Total operating revenues	$3,710,533	$3,586,390	$3,667,461
Percent change	3.5%	(2.2)%	8.3%

Retail revenues of $3.0 billion in 2002 increased $204 million (7.4 percent) from the prior year, decreased $205 million (6.9 percent) in 2001, and increased $142 million (5 percent) in 2000. The primary contributors to the increase in revenues in 2002, shown in the table above, were the positive effect of favorable weather conditions on energy sales and increases in retail base rates (0.6 percent increase in July 2001, and 2 percent increases in October 2001 and April 2002). The Company mitigated these increases to the customer with a decrease to the energy cost recovery factor in April 2002.

Fuel rates billed to customers are designed to fully recover fluctuating fuel costs over a period of time. Lower natural gas prices and increased hydro production combined with decreased costs of purchased power have resulted in an $83 million reduction in under-recovered fuel costs. At December 31, 2002, the Company had completely recovered its previously under-recovered fuel cost. Fuel revenues have no effect on net income because they represent the recording of revenues to offset fuel expenses.

Energy sales for resale outside the service area are predominantly unit power sales under long-term contracts to Florida utilities. Economy energy and energy sold under short-term contracts are also sold for resale outside the service area. Revenues from power sales contracts have both a capacity and energy component. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. These capacity and energy components of the unit power contracts and other outside the service area contracts with non-affiliates, were as follows:

	2002	2001	2000
	(in thousands)		
Unit power -			
Capacity	$119,193	$124,720	$127,445
Energy	134,051	134,006	127,911
Other power contracts -			
Capacity	14,613	13,324	11,546
Energy	61,925	91,608	43,964
Total	$329,782	$363,658	$310,866

Capacity revenues from non-affiliates were relatively unchanged over the past three years. There are no significant scheduled declines in capacity until the termination of the unit power sales contracts in 2010.

Revenues from sales to affiliated companies within the Southern electric system, as well as purchases of energy, will vary from year to year depending on demand and the availability and cost of generating resources at each company. These transactions did not have a significant impact on earnings.

Other operating revenues in 2002 decreased $11 million (9.9 percent) from 2001 due to a decrease in revenues from gas-fueled co-generation steam facilities primarily from lower gas prices and lower demand. Since co-generation steam revenues are generally offset by fuel expenses, these revenues did not have a significant impact on earnings.

The $21 million (23.9 percent) increase in other operating revenues in 2001 and $20 million (30.5 percent) increase in 2000 were primarily attributed to increased steam sales in conjunction with the operation of the Company's co-generation facilities, fuel sales, and rent from electric property.

Kilowatt-hour (KWH) sales for 2002 and the percent change by year were as follows:

	KWH	Percent Change		
	2002	2002	2001	2000
	(millions)			
Residential	17,403	9.6%	(5.3)%	6.8%
Commercial	13,363	4.4	(1.5)	5.5
Industrial	21,103	3.1	(7.4)	0.7
Other	204	3.7	(3.9)	2.3
Total retail	52,073	5.5	(5.2)	3.8
Sales for resale -				
Non-affiliates	15,554	1.8	2.9	19.4
Affiliates	8,844	-	64.7	6.7
Total	76,471	4.1	1.6	6.9

Residential energy sales for 2002 experienced a 9.6 percent increase over the prior year and total retail energy sales grew by 5.5 percent primarily as a result of warmer summer temperatures and colder winter weather conditions compared to the previous year.

Although retail sales to industrial customers increased 3.1 percent in 2002, overall sales to industrial customers remain depressed due to the continuing effect of sluggish economic conditions.

Retail energy sales in 2001 decreased by 5.2 percent due to milder temperatures and an economic downturn in the Company's service area. This was offset by an increase in sales for resale to affiliates. Increased operation of the Company's combined cycle facilities due to lower natural gas prices and an increase in the Company's combined cycle capacity contributed to the increase in sales for resale.

The increase in 2000 retail energy sales was primarily due to the strength of business and economic conditions in the Company's service area. Residential energy sales experienced a 6.8 percent increase over the prior year primarily as a result of warmer summer temperatures and colder winter weather conditions compared to 1999.

Expenses

Total 2002 operating expenses of $2.7 billion increased by $13 million or 0.5 percent over the previous year. This slight increase is mainly due to a $35 million increase in administrative and general expenses primarily related to employee salaries, insurance expense and injuries and damages expense, a $19 million increase in production expenses related to boiler plant maintenance, and a $15 million increase in depreciation and amortization expenses due to an increase in depreciable property. These increases are offset by a $43 million decrease in purchased power expenses and a $14 million decrease in fuel expenses related to lower coal prices. Fuel expenses, including purchased power, are offset by fuel revenues and have no effect on net income.

In 2001 total operating expenses of $2.7 billion were down $50 million or 1.8 percent compared with 2000. This decline is mainly due to an $18 million net decrease in fuel and purchased power costs related to lower fuel prices, increased hydro generation and added capacity. The Company also had a $56 million decrease in non-production operation and maintenance expense related to settlements received in connection with the Company's insurance program, lower costs related to services provided by the system service company and Southern Nuclear, and a reduction to the natural disaster reserve accrual. These decreases in expense were partially offset by a $19 million increase in depreciation and amortization due to an increase in depreciable property.

Total operating expenses of $2.7 billion in 2000 were up $235 million or 9.4 percent compared with the prior year. This increase was mainly due to a $183 million increase in fuel and purchased power costs as a result of warmer summer temperatures and colder winter weather conditions compared to 1999, accompanied by a $23 million increase in maintenance expenses related to overhead line clearing.

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by system load, the unit cost of fuel consumed, and the availability of hydro and nuclear generating units. The amount and sources of generation and the average cost of fuel per net KWH generated were as follows:

	2002	2001	2000
Total generation (billions of KWHs)	71	68	65
Sources of generation (percent) --			
Coal	62	64	72
Nuclear	19	18	19
Hydro	6	6	3
Gas	13	12	6
Average cost of fuel per net KWH generated (cents) --	1.47	1.56	1.54

In 2002, total fuel and purchased power expenses of $1.2 billion decreased $75 million (5.8 percent) due primarily to lower average fuel cost, while total energy sales increased 3,012 million kilowatt hours (4.1 percent) compared with the amounts recorded in 2001. Fuel and purchased power expenses in 2001 decreased $18 million (1.4 percent) compared to 2000 because of milder temperatures in 2001. Fuel and purchased power expenses increased $183 million (16 percent) in 2000 compared to 1999 because of hotter-than-normal summer weather in 2000.

Purchased power consists of purchases from affiliates in the Southern electric system and non-affiliated companies. Purchased power transactions among the Company and its affiliates will vary from period to period depending on demand, the availability, and the variable production cost of generating resources at each company. During 2002 purchased power transactions from non-affiliates decreased $54 million (37 percent) due to the addition in May 2001 of a combined cycle unit which generated 6.1 billion kilowatt hours in 2002, an 18.4 percent increase over the previous year. Purchased power transactions from non-affiliates also declined in 2001 because of the addition of the combined cycle unit and an increase in hydro generation resulting in a $20 million (12 percent) decline from the year 2000.

Depreciation and amortization expense increased 3.9 percent in 2002, 5.2 percent in 2001, and 4.9 percent in 2000. These increases reflect additions to property, plant, and equipment.

Allowance for Funds Used During Construction (AFUDC) increased $4 million (57.5 percent) in 2002 due to an increase in the amount of construction work in progress over the prior year. AFUDC decreased $16 million (68.9 percent) in 2001 due to completion of construction of Plant Barry Unit 7 and placing it in service in May 2001. In 2000, AFUDC increased $11 million (94.6 percent) as a result of this construction.

Interest expense decreased $26 million (9.9 percent) in 2002. The decrease reflects a decrease in interest on long-term debt due to refinancing activities. Interest expense increased $3 million (1.1 percent) in 2001 compared to 2000. In 2000 interest expense was relatively flat when compared to the previous year.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. In addition, the income tax laws are also based on historical costs. Therefore, inflation creates an economic loss because the Company is recovering its costs of investments in dollars that have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations, such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

Future Earnings Potential

General

The results of continuing operations for the past three years are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors. The major factor is the ability of the Company to achieve energy sales growth while containing costs and maintaining a stable regulatory environment. Growth in energy sales is subject to a number of factors. These factors include weather, competition, new short- and long-term contracts with neighboring utilities, energy conservation practiced by customers, the elasticity of demand, and the rate of economic growth in the Company's service area.

Assuming normal weather, sales to retail customers are projected to grow approximately 1.8 percent annually on average during 2003 through 2007.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in the state of Alabama. Prices for electricity provided by the Company to retail customers are set by the Alabama Public Service Commission (APSC) under cost-based regulatory principles.

Rates for the Company can be adjusted periodically within certain limitations based on earned retail rate of return compared with an allowed return. Increases in retail rates of 2 percent were effective in April 2002 and October 2001 in accordance with the Rate Stabilization Equalization plan. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information.

The rates also provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP (Certificated New Plant). Effective July 2001, the Company's retail rates were adjusted by 0.6 percent under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001.

In April 2000, the APSC approved an amendment to the Company's existing rate structure to provide for the recovery of retail costs associated with certified purchased power agreements. In November 2000, the APSC certified a seven-year purchased power agreement pertaining to a 615 megawatt wholesale generating facility under construction in Autaugaville, Alabama (Plant Harris), which was sold to Southern Power in June 2001. All of the 615 megawatts are scheduled to be available beginning in June 2003. In addition, the APSC certified a seven-year purchase power agreement with a third party for approximately 630 megawatts; one half of the capacity will be available beginning in 2003, while the remaining half is scheduled to be available beginning in 2004. Rate CNP will adjust retail rates one month after the contracted capacity delivery is scheduled to begin.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pre-tax pension income of approximately $56 million in 2002. Future pension income is dependent on several factors including trust earnings and changes to the plan. Current estimates indicate a reversal of recording pension income to recording pension expense by as early as 2007. Postretirement benefit costs for the Company were $23 million in 2002 and are expected to continue to trend upward. A portion of pension income is capitalized based on construction related labor charges. For the Company, pension income and postretirement benefits are a component of the regulated rates and do not have a significant effect on net income. For more information see Note 2 to the financial statements.

Proposed nuclear security legislation is expected to be introduced in the 108th Congress. The Nuclear Regulatory Commission is also considering additional security measures for licensees that could require immediate implementation. Any such requirements could have a significant impact on the Company's nuclear power plant and result in increased operation and maintenance expenses as well as additional capital expenditures. The impact of any new requirements would depend upon the development and implementation of the regulations.

The Company is involved in various matters being litigated. See Note 3 to the financial statements for information regarding material issues that could possibly affect future earnings.

Compliance costs related to current and future environmental laws and regulations could affect earnings if such costs are not fully recovered. The Clean Air Act and other important environmental items are discussed later under "Environmental Matters."

Industry Restructuring

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the primary agents of change has been the Energy Policy Act of 1992 (Energy Act). The Energy Act allows independent power producers (IPPs) to access a utility's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build power plants for a utility's large industrial and/or commercial customers where retail access is allowed and to sell excess energy to other utilities. Also, electricity sales for resale rates were affected by numerous new energy suppliers, including power marketers and brokers.

This past year, merchant energy companies and traditional electric utilities with significant energy marketing and trading activities came under severe financial pressures. Many of these companies have completely exited or drastically reduced all energy marketing and trading activities and sold foreign and domestic electric infrastructure assets. The Company has not experienced any material financial impact regarding its limited energy trading operations through SCS and recent generating capacity additions.

Although the Energy Act does not provide for retail customer access, it was a major catalyst for the recent restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives that promote wholesale and retail competition are in varying stages. Among other things, these initiatives allow retail customers in some states to choose their electricity provider. Some states have approved initiatives that result in a separation of the ownership and/or operation of generating facilities from the ownership and/or operation of transmission and distribution facilities. While various restructuring and competition initiatives have been discussed in Alabama, none have been enacted. In October 2000, the APSC completed a two-year study of electric industry restructuring, concluding that (i) restructuring of the electric utility industry in Alabama was not in the public interest and (ii) the APSC itself would not mandate retail competition or electric industry restructuring without enabling state legislation. Electric utility restructuring would require numerous issues to be resolved, including significant ones relating to recovery of any stranded investments, full cost recovery of energy produced, and other issues related to the energy crisis that occurred in California.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation and competition. Conversely, if the Company does not remain a low-cost producer and provide quality service, then energy sales growth could be limited, and this could significantly erode earnings.

FERC Matters

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final ruling on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Southern Company and its operating companies, including the Company, have submitted a series of status reports informing the FERC of progress toward the development of a Southeastern RTO. In these status reports, Southern Company explained that it is developing a for-profit RTO known as SeTrans with a number of non-jurisdictional cooperative and public power entities. In 2001, Entergy Corporation and Cleco Power joined the SeTrans development process. In 2002, the sponsors of SeTrans established a Stakeholder Advisory Committee, which will participate in the development of the RTO, and held public meetings to discuss the SeTrans proposal. On October 10, 2002, the FERC granted Southern Company's and other SeTrans' sponsors petition for a declaratory order regarding the governance structure and the selection process for the Independent System Administrator (ISA) of the SeTrans RTO. The FERC also provided guidance on other issues identified in the petition. The SeTrans sponsors announced the selection of ESB International, Ltd. (ESBI) to be the preferred ISA candidate. Should negotiations with this candidate successfully conclude with final agreement among the parties, the SeTrans sponsors intend to seek any state and federal regulatory or other approvals necessary for formation of the SeTrans RTO and the approval of ESBI to serve in the capacity of the SeTrans ISA. The creation of SeTrans is not expected to have a material impact on the Company's financial statements; however, the outcome of this matter cannot now be determined.

In July 2002, the FERC issued a notice of proposed rulemaking regarding open access transmission service and standard electricity market design. The proposal, if adopted, would among other things: (1) require transmission assets of jurisdictional utilities to be operated by an independent entity; (2) establish a standard market design; (3) establish a single type of transmission service that applies to all customers; (4) assert jurisdiction over the transmission component of bundled retail service; (5) establish a generation reserve margin; (6) establish bid caps for a day ahead and spot energy markets; and (7) revise the FERC policy on the pricing of transmission expansions. Comments on certain aspects of the proposal have been submitted by Southern Company and the Company. Any impact of this proposal on the Company will depend on the form in which final rules may be ultimately adopted; however, the Company's revenues, expenses, assets, and liabilities could be adversely affected by changes in the transmission regulatory structure in its regional power market.

In 2002, the Company initiated the relicensing process for the Company's seven hydroelectric projects on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and the Smith and Bankhead Projects on the Warrior River. The FERC licenses for all of these nine projects expire in 2007. Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company.

Accounting Policies

Critical Policy

The Company's significant accounting policies are described in Note 1 to the financial statements. The Company's only critical accounting policy involves rate regulation. The Company is subject to the provisions of FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation. In the event that a portion of the Company's operation is no longer subject to these provisions, the Company would be required to write off related regulatory assets and liabilities that are not specifically recoverable and determine if any other assets have been impaired. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

New Accounting Standards

Derivatives

Effective January 2001, the Company adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. In October 2002, the Emerging Issues Task Force (EITF) of the FASB announced accounting changes related to energy trading contracts in Issue No. 02-03. In October 2002, the Company prospectively adopted the EITF's requirements to reflect the impact of certain energy trading contracts on a net basis. This change had no material impact on the Company's income statement. Another change also required certain energy trading contracts to be accounted for on an accrual basis effective January 2003. This change had no impact on the Company's current accounting treatment.

Asset Retirement Obligations

Prior to January 2003, the Company accrued for the ultimate cost of retiring most long-lived assets over the life of the related asset through depreciation expense. FASB Statement No. 143, Accounting for Asset Retirement Obligations, establishes new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement must be recorded in the period in which the liability is incurred. The cost must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Additionally, Statement No. 143

does not permit non-regulated companies to continue accruing future retirement costs for long-lived assets that they do not have a legal obligation to retire. For more information regarding the impact of adopting this standard effective January 1, 2003, see Note 1 to the financial statements under "Regulatory Assets and Liabilities" and "Depreciation and Nuclear Decommissioning."

Guarantees

In 2002, the FASB issued Interpretation No. 45, Accounting and Disclosure Requirements for Guarantees. This interpretation requires disclosure of certain direct and indirect guarantees as reflected in Note 8 to the financial statements under "Guarantees." Also, the interpretation requires recognition of a liability at inception for certain new or modified guarantees issued after December 31, 2002. The adoption of Interpretation No. 45 in January 2003 did not have a material impact on the Company's financial statements.

FINANCIAL CONDITION

Overview

Over the last several years the Company's financial condition has remained stable with emphasis on cost control measures combined with significantly lower cost of capital, achieved through the refinancing and/or redemption of higher-cost long-term debt and preferred stock.

The Company had gross property additions of $635 million in 2002. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, principally from earnings and non-cash charges to income such as depreciation and deferred income taxes. The Statements of Cash Flows provide additional details.

Credit Rating Risk

The Company does not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

Exposure to Market Risk

The Company is exposed to market risks, including changes in interest rates and certain commodity prices. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

The weighted average interest rate on variable long-term debt outstanding at December 31, 2002 was 1.64%. If the Company sustained a 100 basis point change in interest rates for all variable long-term debt, the change would affect annualized interest expense by $10.5 million. To further mitigate the Company's exposure to interest rates, it has entered into interest rate swaps that were designed as cash flow hedges of variable rate debt or anticipated debt issuances. See Note 1 and Note 7 to the financial statements under "Financial Instruments" for additional information. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term.

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market.

In addition, in October 2001, the APSC approved a revision to the Company's Rate ECR (Energy Cost Recovery) allowing the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at its electric generating facilities. This revision also includes the cost of financial instruments used for hedging market price risk up to 75 percent of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5 percent of the Company's natural gas budget for that year.

At December 31, 2002, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. The changes in fair value of derivative energy contracts and year-end valuations were as follows:

	Changes in Fair Value	
	2002	2001
	(in thousands)	
Contracts beginning of year	$ 214	$ 567
Contracts realized or settled	(21,088)	(509)
New contracts at inception	-	-
Changes in valuation techniques	-	-
Current period changes	42,276	156
Contracts end of year	$ 21,402	$ 214

	Source of Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in thousands)		
Actively quoted	$21,402	$26,462	$(5,060)
External sources	-	-	-
Models and other methods	-	-	-
Contracts end of Year	$21,402	$26,462	$(5,060)

Unrealized gains and losses from mark to market adjustments on contracts related to the retail fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery clause. Gains and losses on contracts that do not represent hedges are recognized in the Statements of Income as incurred. At December 31, 2002, the fair value of derivative energy contracts reflected in the financial statements was as follows:

	Amounts
	(in millions)
Regulatory liabilities, net	$21.3
Other comprehensive income	-
Net income	0.1
Total fair value	$21.4

For the years ended December 31, 2002 and 2001, approximately $(2.0) million and $2.0 million, respectively, of gains (losses) were recognized in income.

Financing Activities

In 2002, the Company's financing costs decreased due to lower interest rates despite the issuance of new debt during the year. New issues during 2000 through 2002 totaled $2.0 billion and retirement or repayment of higher-cost securities totaled $1.5 billion.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 2000 through 2002, as of year-end, were as follows:

	2002	2001	2000
Long-term debt interest rate	5.05%	5.72%	6.60%
Preferred stock dividend rate	5.17	4.79	5.18
Preferred securities dividend rate	5.25	6.96	7.38

The Company's current liabilities exceed current assets because of securities due within one year. The Company intends to refinance debt that comes due during 2003. Subsequent to December 31, 2002, the Company has refinanced $167 million of securities classified as current on the Balance Sheet with long-term securities. An additional $250 million of securities has been issued to retire long-term debt and for other corporate purposes.

Capital Structure

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 42.6 percent in 2002, 42.8 percent in 2001, and 42.2 percent in 2000. See Note 7 to the financial statements under "Capitalization" for additional information.

Capital Requirements for Construction

Capital expenditures are estimated to be $643 million for 2003, $787 million for 2004, and $948 million for 2005. Over the next three years the Company estimates spending $485 million on environmental related additions including $355 million on Selective Catalytic Reduction facilities, $164 million on Plant Farley including $43 million on replacing reactor vessel heads, $620 million on distribution facilities, and $569 million on transmission additions. See Note 8 to the financial statements for additional details.

Actual construction costs may vary from estimates because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition there can be no assurance that costs related to capital expenditures will be fully recovered.

Other Capital Requirements

In addition to the funds required for the Company's construction program, approximately $1.9 billion will be required by the end of 2005 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost debt and preferred stock and replace these obligations with lower-cost capital if market conditions permit.

As a result of requirements by the Nuclear Regulatory Commission, the Company has established external trust funds for the purpose of funding nuclear decommissioning costs. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the APSC. The amount expensed in 2002 was $18 million. For additional information concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning."

In 1994 the Company also established an external trust fund for postretirement benefits as ordered by the APSC. The cumulative effect of funding these items over a long period will diminish internally funded capital and may require capital from other sources. For additional information, see Note 2 to the financial statements under "Postretirement Benefits."

These capital requirements, lease obligations, purchase commitments, and trust requirements – discussed above and in the financial statements – are summarized as follows:

	2003	2004	2005
		(in millions)	
Construction expenditures	$ 643.0	$787.0	$948.0
Senior Notes	1,117.0	525.0	225.0
Leases -			
Capital	0.9	1.0	0.5
Operating	28.2	27.2	23.4
Purchase commitments -			
Fuel	757.7	768.1	522.6
Purchased Power	53.0	83.0	86.0
Long-term service agreements	25.7	15.2	14.3
Trusts -			
Nuclear decommissioning	20.3	20.3	20.3
Postretirement benefits	5.1	4.9	24.2

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from internal sources. However, the type and timing of any financings – if needed – will depend on market conditions and regulatory approval. In recent years financings primarily have utilized unsecured debt and trust preferred securities.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2003, the Company had approximately $23 million of cash and cash equivalents and $923 million of unused credit arrangements with banks. In addition, the Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs. Cash flows from operating activities were $951 million in 2002, $838 million in 2001, and $827 million in 2000. Credit arrangements are as follows:

		Expires	
Total	Unused	2003	2004
		(in millions)	
$923	$923	$533	$390

Approximately $361 million of the credit facilities expiring in 2003 allow for the execution of term loans for an additional two-year period. See Note 7 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other Southern Company operating companies. At December 31, 2002, the Company had outstanding $37 million of commercial paper.

Environmental Matters

New Source Review Enforcement Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action against the Company in the U.S. District Court in Atlanta, Georgia. The complaint alleges violations of the New Source Review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued to the Company a notice of violation relating to these specific facilities, as well as Plants Greene County and Gaston. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and notice of violation are similar to those brought against and issued to several other electric utilities. These complaints and notices of violation allege that the utilities failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal-burning plants constructed or under construction prior to 1978.

The U.S. District Court in Georgia granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia. The EPA refiled its claims against Alabama Power in the U.S. District Court in Alabama. The Company's case has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA appeal could have a significant adverse impact on the Company, it is a party to that case as well. In February 2003, the U.S. District Court in Alabama extended the stay of the EPA litigation proceeding in Alabama until the earlier of May 6, 2003 or a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the related litigation involving TVA.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day. An adverse outcome in any one of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Environmental Statutes and Regulations

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these environmental requirements will involve significant costs, a major portion of which is expected to be recovered through existing ratemaking provisions. There is no assurance, however, that all such costs will, in fact, be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been and will continue to be, a significant focus for the company. The Title IV acid rain provisions of the Clean Air Act, for example, required significant reductions in sulfur dioxide and nitrogen oxide emissions. Compliance was required in two phases -- Phase I, effective in 1995 and Phase II, effective in 2000. Construction expenditures associated with Phase I and Phase II compliance totaled approximately $88 million.

Some of the expenditures required to comply with the Phase II acid rain requirements also assisted the Company in complying with nitrogen oxide emission reduction requirements under Title I of the Clean Air Act, which were designed to address one-hour ozone nonattainment problems in Birmingham, Alabama. In December 2000, the Alabama Department of Environmental Management (ADEM) adopted revisions to the State Implementation Plan for meeting the one-hour ozone standard. New emission limits to comply with these requirements must be implemented in May 2003. Two plants in the Birmingham area will be affected. Construction expenditures for compliance with these new rules are currently estimated at approximately $270 million, of which $70 million remains to be spent.

To help bring the remaining nonattainment areas into compliance with the one-hour ozone standard, in 1998 the EPA issued regional nitrogen oxide reduction rules. Those rules required 21 states, including Alabama, to reduce and cap nitrogen oxide emissions from power plants and other large industrial sources. Affected sources, including five of the Company's coal-fired plants in Alabama, must comply with the reduction requirements by May 31, 2004. Additional construction expenditures for compliance with these new rules are currently estimated at approximately $292 million, of which $287 million remains to be spent.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. These revisions made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court found the EPA's implementation program for the new ozone standards unlawful and remanded it to the EPA for further rulemaking. The EPA is expected to propose implementation rules designed to address the court's concerns in 2003 and issue final implementation rules in 2004. The remaining legal challenges to the new standards, which were pending before the U.S. Court of Appeals, District of Columbia Circuit, have been resolved.

The EPA plans to designate areas as attainment or nonattainment with the new eight-hour ozone standard by April 2004, based on air quality data for 2001 through 2003. Several areas within the Company's service area are likely to be designated nonattainment under the new ozone standard. State implementation plans, including new emission control regulations necessary to bring those areas into attainment, could be required as early as 2007. Those state plans could require further reductions in nitrogen oxide emissions from power plants. If so, reductions could be required sometime after 2007. The impact of any new standards will depend on the development and implementation of applicable regulations.

The EPA currently plans to designate areas as attainment or nonattainment with the new fine particulate matter standard by the end of 2004. Those area designations will be based on air quality data collected during 2001 through 2003. Several areas within the Company's service area will likely be designated nonattainment under the new particulate matter standard. State implementation plans, including new regulations necessary to bring those areas into attainment could be required as early as the end of 2007. Those state plans will likely require reductions in sulfur dioxide emissions from power plants. If so, the reductions could be required sometime after 2007. Any additional emission reductions and costs associated with the new fine particulate matter standard cannot be determined at this time.

The EPA has also announced plans to issue a proposed Regional Transport Rule for the fine particulate matter standard by the end of 2003 and to finalize the rule in 2005. This rule would likely require year-round sulfur dioxide and nitrogen oxide emission reductions from power plants as early as 2010. If issued, this rule would likely modify other state implementation plan requirements for attainment of the fine particulate matter standard and the eight-hour ozone standard. It is not possible at this time to determine the effect such a rule would have on the Company.

Further reductions in sulfur dioxide could also be required under the EPA's Regional Haze rules. The Regional Haze rules require states to establish Best Available Retrofit Technology (BART) standards for certain sources that contribute to regional haze. The Company has a number of plants that could be subject to these rules. The EPA regional haze program calls for States to submit State Implementation Plans in 2007 and 2008 that contain emission reduction strategies for achieving progress toward the visibility improvement goal. In 2002, however, the U.S. Court of Appeals, District of Columbia Circuit, vacated and remanded the BART provisions of the federal Regional Haze rules to the EPA for further rulemaking. Because new BART rules have not been developed and state visibility assessments are only beginning, it is not possible to determine the effect of these rules on the company at this time.

The EPA's Compliance Assurance Monitoring (CAM) regulations under Title V of the Clean Air Act require that monitoring be performed to ensure compliance with emissions limitations on an ongoing basis. The regulations require certain facilities with Title V operating permits to develop and submit a CAM plan to the appropriate permitting authority upon applying for renewal of the facility's Title V operating permit. The Company is in the process of developing CAM plans, which could indicate a need for improved particulate matter controls at affected facilities. Because the plans are still in the early stages of development, the Company cannot determine the extent to which improved controls could be required or the costs associated with any necessary improvements. Actual ongoing monitoring costs are expensed as incurred and are not material for any period presented.

In December 2000, having completed its utility studies for mercury and other hazardous air pollutants (HAPS), the EPA issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is being developed under the Maximum Achievable Control Technology provisions of the Clean Air Act. The EPA currently plans to issue proposed rules regulating mercury emissions from electric utility boilers by the end of 2003, and those regulations are scheduled to be finalized by the end of 2004. Compliance could be required as early as 2007. Because the rules have not yet been proposed, the costs associated with compliance cannot be determined at this time.

In December 2002, the EPA issued final and proposed revisions to the New Source Review program under the

Clean Air Act. In February 2003, several northeastern states petitioned the D.C. Circuit Court for a stay of the final rules. The proposed rules are open to public comment and may be revised before being finalized by the EPA. If fully implemented, these proposed and final regulations could affect the applicability of the New Source Review provisions to activities at the Company's facilities. In any event, any final regulations must be adopted by the states in the Company's service area in order to apply to the Company's facilities. The effect of these proposed and final rules cannot be determined at this time.

Several major bills to amend the Clean Air Act to impose more stringent emissions limitations have been proposed. Three of these, the Bush Administration's Clear Skies Act, the Clean Power Act of 2002, and the Clean Air Planning Act of 2002, proposed to further limit power plant emissions of sulfur dioxide, nitrogen oxides, and mercury. The latter two bills also proposed to limit emissions of carbon dioxide. None of these bills were enacted into law in the last Congress. Similar bills have been, and are anticipated to be, introduced this year. The Bush Administration's Clear Skies Act was recently reintroduced, and President Bush has stated that it will be a high priority for the Administration. Other bills already introduced include the Climate Stewardship Act of 2003, which proposes capping greenhouse gas emissions. The cost impacts of such legislation would depend upon the specific requirements enacted.

Domestic efforts to limit greenhouse gas emissions have been spurred by international discussions surrounding the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes international constraints on the emissions of greenhouse gases. The Bush Administration does not support U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation and has instead announced a new voluntary climate initiative which seeks an 18 percent reduction by 2012 in the rate of greenhouse gas emissions relative to the dollar value of the U.S. economy. The Company is involved in a voluntary electric utility industry sector climate change initiative in partnership with the government. Because this initiative is still under development, it is not possible to determine the effect on the company at this time.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and will recognize in its financial statements costs to clean up known sites. The Company may be liable for a portion or all required cleanup costs for additional sites that may require environmental remediation. The Company has not incurred any significant cleanup costs to date.

Under the Clean Water Act, the EPA is developing new rules aimed at reducing impingement and entrainment of fish and fish larvae at cooling water intake structures that will require numerous biological studies, and perhaps, retrofits to some intake structures at existing power plants. The new rule was proposed in February 2002 and will be finalized by August 2004. The impact of any new standards will depend on the development and implementation of applicable regulations.

Also, under the Clean Water Act, the EPA and ADEM are developing total maximum daily loads (TMDLs) for certain impaired waters. Establishment of maximum loads by the EPA or ADEM may result in lowering permit limits for various pollutants and a requirement to take additional measures to control non-point source pollution (e.g., storm water runoff) at facilities discharging into waters for which TMDLs are established. Because the effect on the Company will depend on the actual TMDLs and permit limitations established by the implementing agency, it is not possible to determine the effect on the Company at this time.

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including limits on pollutant discharges to impaired waters, hazardous waste disposal requirements, and other regulatory matters. The impact of any new standards will depend on the development and implementation of applicable regulations.

Several major pieces of environmental legislation are periodically considered for reauthorization or amendment by Congress. These include: the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with possible additional federal or state legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could also significantly affect the Company. The impact of any new legislation, or changes to existing legislation, could affect many areas of the Company's operations. The full impact of any such changes cannot, however, be determined at this time.

Cautionary Statement Regarding Forward-Looking Information

The Company's 2002 Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning projected retail sales growth and scheduled completion of new generation. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other comparable terminology. The Company cautions that there are various important factors that could cause actual results to differ materially from those indicated in the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, and also changes in environmental and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action against the Company; the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates; the impact of fluctuations in commodity prices, interest rates, and customer demand; state and federal rate regulations; political, legal, and economic conditions and developments in the United States; internal restructuring or other restructuring options that may be pursued; the ability of counterparties of the Company to make payments as and when due; the effects of, and changes in, economic conditions in the areas in which the Company operates, including the current soft economy; the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar such incidents or responses to such incidents; financial market conditions and the results of financing efforts; the timing and acceptance of the Company's new product and service offerings; the ability of the Company to obtain additional generating capacity at competitive prices; weather and other natural phenomena; and other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed from time to time by the Company with the Securities and Exchange Commission.

STATEMENTS OF INCOME
For the Years Ended December 31, 2002, 2001, and 2000
Alabama Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Operating Revenues:			
Retail sales	$2,951,217	$2,747,673	$2,952,707
Sales for resale --			
Non-affiliates	474,291	485,974	461,730
Affiliates	188,163	245,189	166,219
Other revenues	96,862	107,554	86,805
Total operating revenues	3,710,533	3,586,390	3,667,461
Operating Expenses:			
Operation --			
Fuel	969,521	1,000,828	963,275
Purchased power --			
Non-affiliates	90,998	144,991	164,881
Affiliates	158,121	147,967	184,014
Other	574,979	508,264	538,529
Maintenance	279,406	275,510	301,046
Depreciation and amortization	398,428	383,473	364,618
Taxes other than income taxes	216,919	214,665	209,673
Total operating expenses	2,688,372	2,675,698	2,726,036
Operating Income	1,022,161	910,692	941,425
Other Income and (Expense):			
Allowance for equity funds used during construction	11,168	7,092	22,769
Interest income	13,991	15,101	16,152
Equity in earnings of unconsolidated subsidiaries	3,399	4,494	3,156
Interest expense, net of amounts capitalized	(225,706)	(246,436)	(235,331)
Distributions on preferred securities of subsidiary	(24,599)	(24,775)	(25,549)
Other income (expense), net	(32,184)	(15,671)	(24,995)
Total other income and (expense)	(253,931)	(260,195)	(243,798)
Earnings Before Income Taxes	768,230	650,497	697,627
Income taxes	292,436	248,597	261,555
Earnings Before Cumulative Effect of Accounting Change	475,794	401,900	436,072
Cumulative effect of accounting change-- less income taxes of $215 thousand	-	353	-
Net Income	475,794	402,253	436,072
Dividends on Preferred Stock	14,439	15,524	16,156
Net Income After Dividends on Preferred Stock	$ 461,355	$ 386,729	$ 419,916

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2002, 2001, and 2000
Alabama Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Operating Activities:			
Net income	$ 475,794	$ 402,253	$ 436,072
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	465,325	437,490	412,998
Deferred income taxes and investment tax credits, net	48,828	(21,569)	66,166
Pension, postretirement, and other employee benefits	(34,464)	(58,118)	(53,362)
Other, net	(50,863)	(64,533)	15,659
Changes in certain current assets and liabilities --			
Receivables, net	(46,458)	88,325	(125,652)
Fossil fuel stock	25,535	(38,663)	23,967
Materials and supplies	3,728	(13,025)	(10,662)
Other current assets	6,889	(15,474)	(6,613)
Accounts payable	10,587	(83,077)	107,702
Taxes accrued	(40,922)	46,187	3,266
Other current liabilities	86,850	158,110	(42,507)
Net cash provided from operating activities	950,829	837,906	827,034
Investing Activities:			
Gross property additions	(634,559)	(635,540)	(870,581)
Cost of removal net of salvage	(32,105)	(37,304)	(34,378)
Sales of property	-	102,068	-
Other	2,054	2,533	(15,036)
Net cash used for investing activities	(664,610)	(568,243)	(919,995)
Financing Activities:			
Increase (decrease) in notes payable, net	26,994	(271,347)	184,519
Proceeds --			
Pollution control bonds	-	35,000	-
Senior notes	975,000	442,000	250,000
Preferred securities	300,000	-	-
Common stock	-	15,642	-
Capital contributions from parent company	49,788	107,313	204,371
Redemptions --			
First mortgage bonds	(350,000)	(138,991)	(111,009)
Pollution control bonds	-	(15,000)	-
Senior notes	(415,602)	(3,179)	(5,041)
Other long-term debt	(883)	(842)	(946)
Preferred securities	(347,000)	-	-
Preferred stock	(70,000)	-	-
Payment of preferred stock dividends	(14,176)	(14,942)	(16,110)
Payment of common stock dividends	(431,000)	(393,900)	(417,100)
Other	(22,411)	(9,908)	(951)
Net cash provided from (used for) financing activities	(299,290)	(248,154)	87,733
Net Change in Cash and Cash Equivalents	(13,071)	21,509	(5,228)
Cash and Cash Equivalents at Beginning of Period	35,756	14,247	19,475
Cash and Cash Equivalents at End of Period	$ 22,685	$ 35,756	$ 14,247
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $6,738, $11,690, and $19,953 capitalized	$230,102	$246,316	$237,066
Income taxes (net of refunds)	236,634	223,961	175,303

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

BALANCE SHEETS
At December 31, 2002 and 2001
Alabama Power Company 2002 Annual Report

Assets	2002	2001
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 22,685	$ 35,756
Receivables --		
Customer accounts receivable	240,052	201,566
Unbilled revenues	89,336	80,419
Under recovered regulatory clause revenues	-	83,497
Other accounts and notes receivable	47,535	49,940
Affiliated companies	74,099	72,639
Accumulated provision for uncollectible accounts	(4,827)	(5,237)
Fossil fuel stock, at average cost	73,742	99,278
Materials and supplies, at average cost	187,596	191,324
Other	110,035	74,640
Total current assets	840,253	883,822
Property, Plant, and Equipment:		
In service	13,506,170	13,159,560
Less accumulated provision for depreciation	5,543,416	5,309,557
	7,962,754	7,850,003
Nuclear fuel, at amortized cost	103,088	88,777
Construction work in progress	478,652	357,906
Total property, plant, and equipment	8,544,494	8,296,686
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	45,553	44,742
Nuclear decommissioning trusts	292,297	317,508
Other	16,477	12,244
Total other property and investments	354,327	374,494
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	327,276	334,830
Prepaid pension costs	389,793	329,259
Unamortized debt issuance expense	4,361	8,150
Unamortized premium on reacquired debt	103,819	77,173
Department of Energy assessments	17,144	21,015
Other	104,539	108,031
Total deferred charges and other assets	946,932	878,458
Total Assets	$10,686,006	$10,433,460

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

BALANCE SHEETS
At December 31, 2002 and 2001
Alabama Power Company 2002 Annual Report

Liabilities and Stockholder's Equity	2002	2001
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 1,117,945	$ 5,382
Notes payable	36,991	9,996
Accounts payable --		
Affiliated	109,790	98,268
Other	150,195	151,705
Customer deposits	44,410	42,124
Taxes accrued --		
Income taxes	80,438	113,003
Other	20,561	19,023
Interest accrued	36,344	35,522
Vacation pay accrued	33,901	32,324
Other	114,870	93,589
Total current liabilities	1,745,445	600,936
Long-term debt (See accompanying statements)	2,851,562	3,742,346
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	1,436,559	1,387,661
Deferred credits related to income taxes	177,205	202,881
Accumulated deferred investment tax credits	227,270	238,225
Employee benefits provisions	141,149	115,078
Deferred capacity revenues	33,924	40,730
Other	147,640	130,214
Total deferred credits and other liabilities	2,163,747	2,114,789
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	300,000	347,000
Cumulative preferred stock (See accompanying statements)	247,512	317,512
Common stockholder's equity (See accompanying statements)	3,377,740	3,310,877
Total Liabilities and Stockholder's Equity	$10,686,006	$10,433,460
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2002 and 2001
Alabama Power Company 2002 Annual Report

		2002	2001	2002	2001
		(in thousands)		*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
2023	7.30% - 7.75%	$ -	$ 350,000		
Total first mortgage bonds		-	350,000		
Long-term notes payable --					
Variable rate (1.525% at 1/1/03) due 2003		517,000	167,000		
5.35% to 7.85% due 2003		406,200	406,200		
4.875% to 7.125% due 2004		525,000	525,000		
5.49% due November 1, 2005		225,000	225,000		
7.125% due October 1, 2007		200,000	200,000		
5.375% due October 1, 2008		160,000	160,000		
4.70% to 7.125% due 2010-2048		1,408,800	1,199,402		
Total long-term notes payable		3,442,000	2,882,602		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.50% due 2024		24,400	24,400		
Variable rates (1.56% to 1.80% at 1/1/03) due 2015-2017		89,800	89,800		
Non-collateralized:					
Variable rates (1.42% to 1.95% at 1/1/03) due 2021-2031		445,940	445,940		
Total other long-term debt		560,140	560,140		
Capitalized lease obligations		2,439	3,323		
Unamortized debt premium (discount), net		(35,072)	(48,337)		
Total long-term debt (annual interest requirement -- $202.1 million)		3,969,507	3,747,728		
Less amount due within one year		1,117,945	5,382		
Long-term debt excluding amount due within one year		$2,851,562	$3,742,346	42.1%	48.5%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2002 and 2001
Alabama Power Company 2002 Annual Report

	2002	2001	2002	2001
	(in thousands)		(percent of total)	
Company Obligated Mandatorily Redeemable Preferred Securities:				
$25 liquidation value --				
4.75%	$ 100,000	$ -		
5.50%	200,000	-		
7.375%	-	97,000		
7.60%	-	200,000		
Auction rate (3.60% at 1/1/02)	-	50,000		
Total (annual distribution requirement -- $15.8 million)	300,000	347,000	4.4	4.5
Cumulative Preferred Stock:				
$100 par or stated value --				
4.20% to 4.92%	47,512	47,512		
$25 par or stated value --				
5.20% to 5.83%	200,000	200,000		
Auction rates -- at 1/1/02				
3.10% to 3.557%	-	70,000		
Total (annual dividend requirement -- $12.8 million)	247,512	317,512	3.7	4.1
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 6,000,000 shares				
Outstanding - 6,000,000 shares				
Par value	240,000	240,000		
Paid-in capital	1,900,464	1,850,676		
Premium on Preferred Stock	99	99		
Retained earnings	1,250,594	1,220,102		
Accumulated other comprehensive income (loss)	(13,417)	-		
Total common stockholder's equity	3,377,740	3,310,877	49.8	42.9
Total Capitalization	$6,776,814	$7,717,735	100.0%	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2002, 2001, and 2000
Alabama Power Company 2002 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Other Comprehensive Income (loss)	Total
				(in thousands)		
Balance at December 31, 1999	$224,358	$1,538,992	$99	$1,225,414	$ -	$2,988,863
Net income after dividends on preferred stock	-	-	-	419,916	-	419,916
Capital contributions from parent company	-	204,371	-	-	-	204,371
Cash dividends on common stock	-	-	-	(417,100)	-	(417,100)
Other	-	-	-	(278)	-	(278)
Balance at December 31, 2000	224,358	1,743,363	99	1,227,952	-	3,195,772
Net income after dividends on preferred stock	-	-	-	386,729	-	386,729
Capital contributions from parent company	-	107,313	-	-	-	107,313
Cash dividends on common stock	-	-	-	(393,900)	-	(393,900)
Issuance of common stock	15,642	-	-	-	-	15,642
Other	-	-	-	(679)	-	(679)
Balance at December 31, 2001	240,000	1,850,676	99	1,220,102	-	3,310,877
Net income after dividends on preferred stock	-	-	-	461,355	-	461,355
Capital contributions from parent company	-	49,788	-	-	-	49,788
Other comprehensive income (loss)	-	-	-	-	(13,417)	(13,417)
Cash dividends on common stock	-	-	-	(431,000)	-	(431,000)
Other	-	-	-	137	-	137
Balance at December 31, 2002	$240,000	$1,900,464	$99	$1,250,594	$(13,417)	$3,377,740

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2002, 2001, and 2000
Alabama Power Company 2002 Annual Report

	2002	2001	2000
		(in thousands)	
Net income after dividends on preferred stock	$461,355	$386,729	$419,916
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(2,536)	(4,172)	-	-
Changes in fair value of qualifying hedges, net of tax of $(5,621)	(9,245)	-	-
Total other comprehensive income (loss)	(13,417)	-	-
Comprehensive Income	$447,938	$386,729	$419,916

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five operating companies, Southern Power Company (Southern Power), a system service company, Southern Communications Services (Southern LINC), Southern Company Gas (Southern GAS), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The operating companies -- Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company -- provide electric service in four southeastern states. Southern Power constructs, owns, and manages Southern Company's competitive generation assets and sells electricity at market-based rates in the wholesale market. Contracts among the operating companies and Southern Power -- related to jointly-owned generating facilities, interconnecting transmission lines, or the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission. The system service company provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications services to the operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern GAS, which began operation in August 2002, is a competitive retail natural gas business serving communities in Georgia. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases, alternative fuel products, and an energy service business. Southern Nuclear provides services to the operating companys' nuclear power plants.

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both Southern Company and its subsidiaries are subject to the regulatory provisions of the PUHCA. The Company is also subject to regulation by the FERC and the Alabama Public Service Commission (APSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its respective regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation.

Affiliate Transactions

The Company has an agreement with the system service company under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $218 million, $183 million, and $187 million during 2002, 2001, and 2000, respectively. Cost allocation methodologies used by the system service company are approved by the SEC and management believes they are reasonable.

The Company has an agreement with Southern Nuclear to operate Plant Farley and provide the following nuclear-related services at cost: general executive and advisory services; general operations, management and technical services; administrative services including procurement, accounting, statistical analysis, and employee relations; and other services with respect to business and operations. Costs for these services amounted to $154 million, $160 million, and $148 million during 2002, 2001, and 2000, respectively.

The Company has an agreement with Mississippi Power under which Mississippi Power owns a portion of Plant Greene County. The Company operates Plant Greene County and Mississippi Power reimburses the Company for its proportionate share of expenses which were $6.4 million in 2002. See Note 4 for additional information.

In 2001, the Company had under construction a 1,230 megawatt combined cycle facility in Autaugaville, Alabama (Plant Harris). In June 2001, the Company sold this project to Southern Power. The Company has entered into an agreement with Southern Power to operate and maintain Plant Harris and provide fuel at cost beginning in June 2003.

The operating companies, including the Company, Southern Power, and Southern GAS may jointly enter into various types of wholesale energy, natural gas and certain other contracts, either directly or through the system service company as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, Accounting for the Effects of Certain Types of Regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the Balance Sheets at December 31 relate to the following:

	2002	2001
	(in millions)	
Deferred income tax charges	$ 327	$ 335
Premium on reacquired debt	104	77
Department of Energy assessments	17	21
Vacation pay	34	32
Deferred income tax credits	(177)	(203)
Natural disaster reserve	(12)	(12)
Fuel-hedging assets	-	4
Fuel-hedging liabilities	(21)	(2)
Other regulatory assets	56	55
Other regulatory liabilities	(12)	(4)
Total	$ 316	$ 303

See "Depreciation and Nuclear Decommissioning" in this note for information regarding significant regulatory assets and liabilities created as a result of the January 1, 2003, adoption of FASB Statement No. 143, Accounting for Asset Retirement Obligations.

In the event that a portion of the Company's operations is no longer subject to the provisions of FASB Statement No. 71, the Company would be required to write off related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition the Company would be required to determine if any impairment to other assets exists, including plant, and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates.

Revenues and Fuel Costs

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the state of Alabama and to wholesale customers in the southeast. Revenues are recognized as services are rendered. Unbilled revenues are accrued at the end of each fiscal period. Fuel costs are expensed as the fuel is used. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between recoverable fuel costs and amounts actually recovered in current regulated periods.

The Company has a diversified base of customers. No single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts continue to average less than 1 percent of revenues.

Fuel expense includes the amortization of the cost of nuclear fuel and a charge based on nuclear generation for the permanent disposal of spent nuclear fuel. Total charges for nuclear fuel included in fuel expense amounted to $63 million in 2002, $58 million in 2001, and $61 million in 2000. The Company has a contract with the U.S. Department of Energy (DOE) that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in January 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient fuel storage capacity is available at Plant Farley to maintain full-core discharge capability until the refueling outage scheduled in 2006 for Farley Unit 1 and the refueling outage scheduled in 2008 for Farley Unit 2. Procurement of on-site dry spent fuel storage capacity at Plant Farley is in progress, with the intent to place the capacity in operation in 2005.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants. This assessment is being paid over a 15-year period, which began in 1993. This fund will be used by the DOE for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The law provides that utilities will recover these payments in the same manner as any other fuel expense. The Company estimates its remaining liability under this law to be approximately $17 million at December 31, 2002. This obligation is recorded in other deferred credits in the accompanying Balance Sheets.

Depreciation and Nuclear Decommissioning

Depreciation of the original cost of depreciable utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2 percent in 2002, 2001, and 2000. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost -- together with the cost of removal, less salvage -- is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation expense includes an amount for the expected cost of decommissioning nuclear facilities and removal of other facilities. Prior to January 2003, in accordance with regulatory requirements, the Company followed the industry practice of accruing for the ultimate cost of retiring most long-lived assets over the life of the related asset as part of the annual depreciation expense provision.

In January 2003, the Company adopted FASB Statement No. 143, Accounting for Asset Retirement Obligations. Statement No. 143 establishes new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement must be recorded in the period in which the liability is incurred. The cost must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life.

There was no cumulative effect to net income resulting from the adoption of Statement No. 143. The Company received an accounting order from the APSC to defer the transition adjustment; therefore, the Company recorded a related regulatory liability of $71 million to reflect the Company's regulatory treatment of these costs under Statement No. 71. The initial Statement No. 143 liability the Company recognized was $301 million, of which $310 million was removed from the accumulated depreciation reserve. The amount capitalized to property, plant, and equipment was $63 million.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. The Company has also identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, a liability for the removal of these assets will not be recorded because no reasonable estimate can be made regarding the timing of any related retirements. The Company will continue to recognize in the income statement its ultimate removal costs in accordance with its regulatory treatment. Any difference between costs recognized under Statement No. 143 and those reflected in rates will be recognized as either a regulatory asset or liability as ordered by the APSC. It is estimated that this annual difference will be approximately $4 million. The APSC regulatory order states that actual asset removal costs will be recoverable in rates.

Statement No. 143 does not permit non-regulated companies to continue accruing future retirement costs for long-lived assets they do not have a legal obligation to retire. However, in accordance with the regulatory treatment of these costs, the Company will continue to recognize the removal costs for these other obligations in their depreciation rates. As of January 1, 2003, the amount included in the accumulated depreciation reserve that represents a regulatory liability for these costs was $550 million.

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial nuclear power reactors to establish a plan for providing with reasonable assurance funds for decommissioning. The Company has established external trust funds to comply with the NRC's regulations. Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the APSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC to ensure that -- over time -- the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission the facility as of the site study year, and ultimate cost is the estimate to decommission the facility as of its retirement date. The estimated costs of decommissioning -- both site study costs and ultimate costs – based on the most current study for Plant Farley were as follows:

Site study year	1998
Decommissioning periods:	
Beginning year	2017
Completion year	2031
	(in millions)
Site study costs:	
Radiated structures	$629
Non-radiated structures	60
Total	$689
	(in millions)
Ultimate costs:	
Radiated structures	$1,868
Non-radiated structures	178
Total	$2,046

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making estimates.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the APSC. The amount expensed in 2002 and fund balances as of December 31, 2002 were as follows:

	(in millions)
Amount expensed in 2002	$ 18
Accumulated provisions:	
External trust funds, at fair value	$292
Internal reserves	34
Total	$326

All of the Company's decommissioning costs are approved for recovery by the APSC through the ratemaking process. Significant assumptions include an estimated inflation rate of 4.5 percent and an estimated trust earnings rate of 7.0 percent. The Company expects the APSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

The Company has informed the NRC that the Company plans to submit an application in September 2003 to extend the operating license for Plant Farley for 20 additional years.

Income Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average lives of the related property.

Allowance For Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the Company records AFUDC. AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. All current construction costs should be included in retail rates. The composite rate used to determine the amount of AFUDC was 8.2 percent in 2002, 7.7 percent in 2001, and 9.6 percent in 2000. AFUDC and interest capitalized, net of income tax, as a percent of net income after dividends on preferred stock was 3.3 percent in 2002 and 2001, and 8.4 percent in 2000.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the estimated cost of funds used during construction.

The cost of replacements of property--exclusive of minor items of property--is capitalized. The cost of maintenance, repairs and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific APSC orders. The Company accrues estimated refueling costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2002, the Company accrued $34.4 million to the nuclear refueling outage reserve and at December 31, the reserve balance was $9.7 million.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment provision is required. Until the assets are disposed of, their estimated fair value is reevaluated when circumstances or events change.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Natural Disaster Reserve

In accordance with an APSC order, the Company has established a Natural Disaster Reserve. The Company is allowed to accrue $250 thousand per month until the maximum accumulated provision of $32 million is attained. Higher accruals to restore the reserve to its authorized level are allowed whenever the balance in the reserve declines below $22.4 million. During 2002, the Company accrued $3 million to the reserve and at December 31, the reserve balance was $11.8 million.

Comprehensive Income

Comprehensive income – consisting of net income and changes in the fair value of qualifying cash flow hedges and changes in additional minimum pension liabilities, less income taxes and reclassifications for amounts included in net income – is presented in the financial statements. The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. For additional information, see Note 7.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. The Company accounts for its stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25. Accordingly, no compensation expense has been recognized because the exercise price of all options granted equaled the fair-market value on the date of grant. When options are exercised, the Company receives a capital contribution from Southern Company equivalent to the related income tax benefit.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts are derivatives. However, in many cases, these contracts qualify as normal purchases and sales and are accounted for under the accrual method. Other contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets or liabilities as appropriate until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Contracts that do not qualify for the normal purchase and sale exception and that do not meet the hedge requirements are marked to market through current period income and are recorded on a net basis in the Statements of Income.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Other Company financial instruments for which the carrying amount did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2002	$3,967	$4,065
At December 31, 2001	3,744	3,800
Preferred Securities:		
At December 31, 2002	300	303
At December 31, 2001	347	346

The fair value for long-term debt and preferred securities was based on either closing market prices or closing prices of comparable instruments.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan that covers substantially all employees. The Company also provides certain non-qualified benefit plans for a selected group of management and highly-compensated employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all employees may become eligible for such benefits when they retire. The Company funds trusts to the extent deductible under federal income tax regulations or to the extent required by the APSC and the FERC. In late 2000, as well as in 2002, the Company adopted several pension and postretirement benefit plan changes that had the effect of increasing benefits to both current and future retirees.

Plan assets consist primarily of domestic and international equities, global fixed income securities, real estate, and private equity investments. The measurement date for plan assets and obligations is September 30 of each year. The weighted average rates assumed in the actuarial calculations for both the pension and postretirement benefit plans were as follows:

	2002	2001	2000
Discount	6.50%	7.50%	7.50%
Annual salary increase	4.00	5.00	5.00
Long-term return on plan assets	8.50	8.50	8.50

Pension Plan

Changes during the year in the projected benefit obligations and in the fair value of plan assets were as follows:

	Projected Benefit Obligations	
	2002	2001
	(in millions)	
Balance at beginning of year	$1,011	$ 925
Service cost	26	25
Interest cost	74	70
Benefits paid	(61)	(56)
Actuarial gain and employee transfers	16	(1)
Amendments	22	48
Balance at end of year	$1,088	$1,011

	Plan Assets	
	2002	2001
	(in millions)	
Balance at beginning of year	$1,584	$1,921
Actual return on plan assets	(106)	(277)
Benefits paid	(61)	(56)
Employee transfers	2	(4)
Balance at end of year	$1,419	$1,584

The accrued pension costs recognized in the Balance Sheets were as follows:

	2002	2001
	(in millions)	
Funded status	$331	$ 573
Unrecognized transition obligation	(10)	(15)
Unrecognized prior service cost	93	78
Unrecognized net gain (loss)	(40)	(322)
Prepaid asset, net	374	314
Portion included in benefit obligations	16	15
Prepaid asset recognized in the Balance Sheets	$390	$ 329

In 2002 and 2001, amounts recognized in the Balance Sheets for accumulated other comprehensive income and intangible assets were $6.7 million and $4.8 million, and $0 and $6.3 million, respectively.

Components of the pension plan's net periodic cost were as follows:

	2002	2001	2000
	(in millions)		
Service cost	$ 26	$ 25	$ 23
Interest cost	74	70	65
Expected return on plan assets	(138)	(131)	(119)
Recognized net actuarial gain	(20)	(22)	(19)
Net amortization	2	1	(1)
Net pension cost (income)	$ (56)	$ (57)	$ (51)

Postretirement Benefits

Changes during the year in the accumulated benefit obligations and in the fair value of plan assets were as follows:

	Accumulated Benefit Obligations	
	2002	2001
	(in millions)	
Balance at beginning of year	$348	$264
Service cost	5	5
Interest cost	26	24
Benefits paid	(20)	(18)
Actuarial gain and employee transfers	46	(13)
Amendments	-	86
Balance at end of year	$405	$348

	Plan Assets	
	2002	2001
	(in millions)	
Balance at beginning of year	$169	$192
Actual return on plan assets	(12)	(24)
Employer contributions	21	19
Benefits paid	(20)	(18)
Balance at end of year	$158	$169

The accrued postretirement costs recognized in the Balance Sheets were as follows:

	2002	2001
	(in millions)	
Funded status	$(247)	$(179)
Unrecognized transition obligation	41	45
Prior service cost	77	82
Unrecognized net actuarial gain	66	(9)
Fourth quarter contributions	8	8
Accrued liability recognized in the Balance Sheets	$ (55)	$ (53)

Components of the plan's net periodic cost were as follows:

	2002	2001	2000
	(in millions)		
Service cost	$ 5	$ 5	$ 4
Interest cost	25	24	19
Expected return on plan assets	(16)	(15)	(13)
Net amortization	9	7	4
Net postretirement cost	$ 23	$ 21	$ 14

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 8.75 percent for 2002, decreasing gradually to 5.25 percent through the year 2010, and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2002 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$32	$28
Service and interest costs	3	2

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2002, 2001, and 2000 were $12 million, $12 million, and $11 million, respectively.

Work Force Reduction Programs

The Company has incurred costs for work force reduction programs totaling $13.6 million, $13.0 million and $2.6 million for the years 2002, 2001 and 2000, respectively. These costs were deferred and are being amortized in accordance with regulatory treatment over 22 month periods. The unamortized balance of these costs was $5.1 million at December 31, 2002.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are also subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent.

The ultimate outcome of such litigation currently filed against the Company cannot be predicted at this time; however, after consultation with legal counsel, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the Company's financial statements.

Environmental Protection Agency Litigation

In November 1999, the EPA brought a civil action in U.S. District Court in Georgia against the Company. The complaint alleges violations of the New Source Review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The EPA concurrently issued to the Company a notice of violation relating to these specific facilities, as well as Plants Greene County and Gaston. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and the notice of violation are similar to those brought against and issued to several other electric utilities. The complaint and the notice of violation allege that the Company failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. The U.S. District Court in Georgia granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia. The EPA refiled its claims against Alabama Power in U.S. District Court in Alabama.

The Company's case has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA appeal involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA appeal could have a significant adverse impact on the Company, it is a party to that case as well. In February 2003, the U.S. District Court in Alabama extended the stay of the EPA litigation proceeding in Alabama until the earlier of May 6, 2003 or a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the related litigation involving TVA.

The Company believes that it complied with applicable laws and the EPA's regulations and interpretations in effect at the time the work in question took place. An adverse outcome of this matter could require substantial capital expenditures that cannot be determined at this time and possibly require payment of substantial penalties. This could affect future results of operations, cash flows, and possibly financial condition if such costs are not recovered through regulated rates.

Retail Rate Adjustment Procedures

The APSC has adopted rates that provide for periodic adjustments based upon the Company's earned return on end-of-period retail common equity. Increases in retail rates of 2 percent were effective in April 2002 and in October 2001 in accordance with the Rate Stabilization Equalization Plan. In March 2002, the APSC approved a revision to the rate adjustment procedures that provides for an annual, rather than quarterly, adjustment and imposes a 3 percent limit on changes in rates in any calendar year. The return on common equity range of 13.0 percent to 14.5 percent remained unchanged.

The rates also provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP (Certificated New Plant). Effective July 2001, the Company's retail rates were adjusted by 0.6 percent under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001.

In April 2000, the APSC approved an amendment to the Company's existing rate structure to provide for the recovery of retail costs associated with certified purchased power agreements. In November 2000, the APSC certified a seven-year purchased power agreement pertaining to a 615 megawatt wholesale generating facility under construction at Plant Harris, which was sold to Southern Power in June 2001. All of the 615 megawatts are scheduled to be available beginning in June 2003. In addition, the APSC certified a seven-year purchased power agreement with a third party for approximately 630 megawatts; one half of the capacity will be available beginning in 2003 while the remaining half is scheduled to be available beginning in 2004. Rate CNP will adjust retail rates one month after the contracted capacity delivery is scheduled to begin.

In October 2001, the APSC approved a revision to the Company's Rate ECR (Energy Cost Recovery) allowing the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at its electric generating facilities. This revision also includes the cost of financial tools used for hedging market price risk up to 75 percent of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5 percent of the Company's natural gas budget for that year.

The Company's ratemaking procedures will remain in effect until the APSC votes to modify or discontinue them.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of Southern Electric Generating Company (SEGCO), which owns electric generating units with a total rated capacity of 1,020 megawatts, together with associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense and a return on equity, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice. The Company's share of expenses totaled \$84 million in 2002, \$80 million in 2001, and \$85 million in 2000 and is included in "Purchased power from affiliates" in the Statements of Income.

In addition the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which \$24.5 million principal amount of pollution control revenue bonds are outstanding. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligation corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2002, the capitalization of SEGCO consisted of \$59 million of equity and \$92 million of debt on which the annual interest requirement is \$2.2 million. SEGCO paid dividends totaling \$5.8 million in 2002, \$0.7 million in 2001, and \$5.1 million in 2000, of which one-half of each was paid to the Company. In addition, the Company recognizes 50 percent of SEGCO's net income.

The Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2002 is as follows:

Facility (Type)	Total Megawatt Capacity	Company Ownership
Greene County (coal)	500	60.00% (1)
Plant Miller Units 1 and 2 (coal)	1,320	91.84% (2)

(1) Jointly owned with an affiliate, Mississippi Power Company.
(2) Jointly owned with Alabama Electric Cooperative, Inc.

Facility	Company Investment	Accumulated Depreciation
	(in millions)	
Greene County	\$105	\$ 51
Plant Miller Units 1 and 2	760	341

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of their plant operating expenses is included in the operating expenses in the Statements of Income.

5. LONG-TERM POWER SALES AGREEMENTS

General

The Company and the other operating companies of Southern Company have entered into long-term contractual agreements for the sale of capacity to certain non-affiliated utilities located outside the system's service area. These agreements are firm and related to specific generating units. Because the energy is generally provided at cost under these agreements, profitability is primarily affected by capacity revenues.

Unit power from Plant Miller is being sold to Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), and Jacksonville Electric Authority (JEA). Under these agreements approximately 1,239 megawatts of capacity are scheduled to be sold annually through the expiration of the contract in 2010. The Company's capacity revenues from these unit power sales amounted to $119 million in 2002, $125 million in 2001, and $127 million in 2000.

Alabama Municipal Electric Authority (AMEA) Capacity Contracts

In October 1991, the Company entered into a firm power sales contract with AMEA entitling AMEA to scheduled amounts of capacity (up to a maximum 80 megawatts) for a period of 15 years. Under the terms of the contract, the Company received payments from AMEA representing the net present value of the revenues associated with the capacity entitlement, discounted at an effective annual rate of 11.19 percent. These payments are being recognized as operating revenues and the discount is amortized to other interest expense as scheduled capacity is made available over the terms of the contract.

To secure AMEA's advance payments and the Company's performance obligation under the contracts, the Company issued and delivered to an escrow agent first mortgage bonds representing the maximum amount of liquidated damages payable by the Company in the event of a default under the contracts. No principal or interest is payable on such bonds unless and until a default by the Company occurs. As the liquidated damages decline, a portion of the bond equal to the decrease is returned to the Company. At December 31, 2002, $32.6 million of these bonds was held by the escrow agent under the contract.

6. INCOME TAXES

At December 31, 2002, the Company's tax-related regulatory assets and liabilities were $327 million and $177 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

Details of the income tax provisions are as follows:

	2002	2001	2000
		(in millions)	
Total provision for income taxes:			
Federal --			
Current	$209	$234	$168
Deferred	41	(20)	60
	250	214	228
State --			
Current	35	37	27
Deferred	7	(2)	7
	42	35	34
Total	$292	$249	$262

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2002	2001
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	$1,081	$1,034
Property basis differences	381	390
Fuel cost adjustment	-	28
Premium on reacquired debt	39	29
Pensions	103	89
Other	38	23
Total	1,642	1,593
Deferred tax assets:		
Capacity prepayments	11	13
Other deferred costs	13	14
Postretirement benefits	18	21
Unbilled revenue	20	18
Other	87	93
Total	149	159
Total deferred tax liabilities, net	1,493	1,434
Portion included in current liabilities, net	(56)	(47)
Accumulated deferred income taxes in the Balance Sheets	$1,437	$1,387

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the Statements of Income. Credits amortized in this manner amounted to $11 million in 2002, 2001, and 2000. At December 31, 2002, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2002	2001	2000
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	3.5	3.5	3.1
Non-deductible book depreciation	1.3	1.5	1.4
Differences in prior years' deferred and current tax rates	(1.2)	(1.3)	(1.3)
Other	(0.5)	(0.5)	(0.7)
Effective income tax rate	38.1%	38.2%	37.5%

Southern Company files a consolidated federal income tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

7. CAPITALIZATION

Mandatorily Redeemable Preferred Securities

Statutory business trusts formed by the Company, of which the Company owns all the common securities, have issued mandatorily redeemable flexible trust preferred securities as follows:

	Date of Issue	Amount (millions)	Rate*	Notes (millions)	Maturity Date
Trust IV	10/2002	$100	4.75%	$103	10/2042
Trust V	10/2002	200	5.50	206	10/2042

* Issued at a five year initial fixed rate and a seven year initial fixed rate for Trust IV and Trust V, respectively, and thereafter, at fixed rates determined through remarketings for specific periods of varying length or at floating rates determined by reference to 3-month LIBOR plus 2.91% and 3.10%, respectively.

Substantially all of the assets of each trust are junior subordinated notes issued by the Company in the respective approximate principal amounts set forth above.

The Company considers that the mechanisms and obligations relating to the preferred securities, taken together, constitute a full and unconditional guarantee by the Company of the Trusts' payment obligations with respect to the preferred securities.

The Trusts are subsidiaries of the Company and accordingly are consolidated in the Company's financial statements.

The securities issued by Trusts I, II, and III were redeemed in 2002.

Pollution Control Bonds

Pollution control obligations represent installment purchases of pollution control facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. With respect to $114.2 million of such pollution control obligations, the Company has authenticated and delivered to the trustees a like principal amount of first mortgage bonds as security for its obligations under the installment purchase agreements. No principal or interest on these first mortgage bonds is payable unless and until a default occurs on the installment purchase agreements. The amount of pollution control revenue bonds outstanding was $560 million at December 31, 2002 and 2001.

Senior Notes

The Company issued a total of $975 million of unsecured senior notes in 2002. The proceeds of these issues were used to redeem higher cost debt and for other general corporate purposes.

At December 31, 2002 and 2001, the Company had $3.4 billion and $2.9 billion, respectively, of senior notes outstanding. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $302 million at December 31, 2002.

Capitalized Leases

The estimated aggregate annual maturities of capitalized lease obligations through 2006 are as follows: $0.9 million in 2003, $1.0 million in 2004, $0.5 million in 2005, and $0.1 million in 2006.

Securities Due Within One Year

A summary of the improvement fund requirements and scheduled maturities and redemptions of long-term debt due within one year at December 31 is as follows:

	2002	2001
	(in thousands)	
First mortgage bond maturities and redemptions	$ -	$4,498
Other long-term debt maturities and redemptions	1,117,945	884
Total long-term debt due within one year	$1,117,945	$5,382

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $923 million (including $454 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds). Of these lines, $533 million expire at various times during 2003 and $390 million expire in 2004. In certain cases, such lines require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees are less than 1/8 of 1 percent for the Company. Because the arrangements are based on an average balance, the Company does not consider any of its cash balances to be restricted as of any specific date. An annual fee is also paid to the agent bank.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65 percent of total capitalization. Exceeding this debt level would result in a default under the credit arrangements. In addition, the credit arrangements typically contain cross default provisions on other indebtedness of the Company that would be triggered if the Company defaulted on other indebtedness above a specified threshold. The Company is currently in compliance with all such covenants. Borrowings under unused credit arrangements totaling $74 million would be prohibited if the Company experiences a material adverse change (as defined in such arrangements).

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time pursuant to arrangements with banks for uncommitted lines of credit and through extendible commercial note programs. At December 31, 2002, there were no extendible commercial notes outstanding. The amount of commercial paper outstanding at December 31, 2002 was $37 million.

At December 31, 2002, the Company had regulatory approval to have outstanding up to $1 billion of short-term borrowings.

Financial Instruments

The Company enters into interest rate swaps to hedge exposure to interest rate changes. Swaps related to fixed rate securities are accounted for as fair value hedges. Swaps related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The swaps are generally structured to mirror the terms of the hedged debt instruments; therefore, no material ineffectiveness has been recorded in earnings. The gain or loss in fair value for cash flow hedges is recorded in other comprehensive income and will be recognized in earnings over the life of the hedged items.

At December 31, 2002, the Company had $1.25 billion notional amount of interest rate swaps outstanding with net deferred losses of $15 million as follows:

Cash Flow Hedges

	Weighted Average			
Maturity	Variable Rate Received	Fixed Rate Paid	Notional Amount	Fair Value (Loss)
			(in millions)	
2003	1.95	3.02	$350	$(5)
2004	1.43	1.63	486	(2)
2003	*	3.05	167	(2)
2003	*	3.96	250	(6)

**Rate has not been set.*

Assets Subject to Lien

The Company's mortgage, as amended and supplemented, securing the first mortgage bonds issued by the Company, constitutes a direct lien on substantially all of the Company's fixed property and franchises.

8. COMMITMENTS

Construction Program

The Company's construction program includes significant projects related to transmission, distribution and generating facilities, including the expenditures necessary to comply with environmental regulation. The Company currently estimates property additions to be $643 million in 2003, $787 million in 2004, and $948 million in 2005.

The capital budget is subject to periodic review and revision, and actual capital costs incurred may vary from estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2002, significant purchase commitments were outstanding in connection with the construction program. There can be no assurance that costs related to capital expenditures will be fully recovered.

Southern Company has guaranteed Southern Power obligations totaling $6.6 million for the Company's construction of transmission interconnection facilities to Plant Harris.

Long-Term Service Agreements

The Company has entered into several Long-Term Service Agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. In summary, the LTSAs stipulate that GE will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total payments to GE under these agreements are currently estimated at $253 million over the life of the agreements, which are approximately 12 to 14 years per unit. However, the LTSAs contain various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned maintenance are recorded as a prepayment in the Balance Sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of electricity. Estimated total long-term obligations at December 31, 2002 were as follows:

	Commitments		
Year	Affiliated	Non-Affiliated	Total
		(in millions)	
2003	$ 37	$ 16	$ 53
2004	49	34	83
2005	49	37	86
2006	49	38	87
2007	49	39	88
2008 and thereafter	111	103	214
Total commitments	$344	$267	$611

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated long-term obligations at December 31, 2002, were as follows:

Year	Commitments
	(in millions)
2003	$ 772
2004	782
2005	537
2006	448
2007	453
2008 and thereafter	280
Total commitments	$3,272

In addition, the system service company acts as agent for the five operating companies, Southern Power, and Southern GAS with regard to natural gas purchases. Natural gas purchases (in dollars) are based on various indices at the actual time of delivery; therefore, only the volume commitments are firm. The Company's committed volumes allocated based on usage projections, as of December 31, 2002, are as follows:

Year	Natural Gas
	(MMBtu)
2003	91,672,637
2004	53,978,335
2005	20,562,820
2006	12,962,557
2007	4,534,876
Total commitments	183,711,225

Additional commitments for fuel will be required to supply the Company's future needs.

Acting as an agent for all of Southern Company's operating companies, Southern Power, and Southern GAS, the system service company may enter into various types of wholesale energy and natural gas contracts. Under these agreements, each of the operating companies, Southern Power, and Southern GAS may be jointly and severally liable for the obligations of each of the operating companies. Accordingly, the creditworthiness of Southern Power and Southern GAS is currently inferior to the creditworthiness of the operating companies. Southern Company has entered into keep-well agreements with each of the operating companies to insure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power or Southern GAS as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $29.6 million in 2002, $27.9 million in 2001, and $20.9 million in 2000. Of these amounts, $19.1 million, $21.1 million, and $20.9 million for 2002, 2001, and 2000, respectively, relates to the railcar leases and is recoverable through the Company's energy cost recovery clause. At December 31, 2002, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Railcars	Vehicles & Other	Total
		(in millions)	
2003	$18.6	$ 9.6	$ 28.2
2004	18.2	9.0	27.2
2005	15.5	7.9	23.4
2006	10.6	5.6	16.2
2007	3.3	2.8	6.1
2008 and thereafter	33.4	4.2	37.6
Total minimum payments	$99.6	$39.1	$138.7

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2004 and 2006, and the Company's maximum obligations are $25.7 million and $66 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2002, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities, as discussed in Note 4, and to certain residual values of leased assets. See "Operating Leases" above.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988 (the Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $9.5 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums which could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $88 million per incident for each licensed reactor it operates, but not more than an aggregate of $10 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $176 million per incident but not more than an aggregate of $20 million to be paid for each incident in any one year.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional cost that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of between 8 to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After this deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL and has elected a 12 week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the three NEIL policies would be $36 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power stations would be covered under their insurance. However, both companies revised their policy terms on a prospective basis to include an industry aggregate for all terrorist acts. The NEIL aggregate, which applies to all claims stemming from terrorism within a 12 month duration, is $3.24 billion plus any amounts that would be available through reinsurance or indemnity from an outside source. The ANI cap is a $300 million shared industry aggregate.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property or replacement power may be subject to applicable state premium taxes.

10. QUARTERLY FINANCIAL INFORMATION (Unaudited)

Summarized quarterly financial data for 2002 and 2001 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2002	$ 802	$191	$ 72
June 2002	924	256	116
September 2002	1,119	393	201
December 2002	865	182	72
March 2001	$ 850	$180	$ 70
June 2001	904	194	75
September 2001	1,061	362	180
December 2001	772	175	62

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 1998-2002
Alabama Power Company 2002 Annual Report

	2002	2001	2000	1999	1998
Operating Revenues (in thousands)	$3,710,533	$3,586,390	$3,667,461	$3,385,474	$3,386,373
Net Income after Dividends on Preferred Stock (in thousands)	$461,355	$386,729	$419,916	$399,880	$377,223
Cash Dividends on Common Stock (in thousands)	$431,000	$393,900	$417,100	$399,600	$367,100
Return on Average Common Equity (percent)	13.80	11.89	13.58	13.85	13.63
Total Assets (in thousands)	$10,686,006	$10,433,460	$10,379,108	$9,648,704	$9,225,698
Gross Property Additions (in thousands)	$634,559	$635,540	$870,581	$809,044	$610,132
Capitalization (in thousands):					
Common stock equity	$3,377,740	$3,310,877	$3,195,772	$2,988,863	$2,784,067
Preferred stock	247,512	317,512	317,512	317,512	317,512
Company obligated mandatorily redeemable preferred securities	300,000	347,000	347,000	347,000	297,000
Long-term debt	2,851,562	3,742,346	3,425,527	3,190,378	2,646,566
Total (excluding amounts due within one year)	$6,776,814	$7,717,735	$7,285,811	$6,843,753	$6,045,145
Capitalization Ratios (percent):					
Common stock equity	49.8	42.9	43.9	43.7	46.1
Preferred stock	3.7	4.1	4.4	4.6	5.3
Company obligated mandatorily redeemable preferred securities	4.4	4.5	4.8	5.1	4.9
Long-term debt	42.1	48.5	46.9	46.6	43.7
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	A1	A1	A1	A1	A1
Standard and Poor's	A	A	A	A+	A+
Fitch	A+	A+	AA-	AA-	AA-
Preferred Stock -					
Moody's	Baa1	Baa1	a2	a2	a2
Standard and Poor's	BBB+	BBB+	BBB+	A-	A
Fitch	A-	A-	A	A	A
Unsecured Long-Term Debt -					
Moody's	A2	A2	A2	A2	A2
Standard and Poor's	A	A	A	A	A
Fitch	A	A	A+	A+	A+
Customers (year-end):					
Residential	1,148,645	1,139,542	1,132,410	1,120,574	1,106,217
Commercial	203,017	196,617	193,106	188,368	182,738
Industrial	4,874	4,728	4,819	4,897	5,020
Other	789	751	745	735	733
Total	1,357,325	1,341,638	1,331,080	1,314,574	1,294,708
Employees (year-end):	6,715	6,706	6,871	6,792	6,631

SELECTED FINANCIAL AND OPERATING DATA 1998-2002 (continued)

Alabama Power Company 2002 Annual Report

	2002	2001	2000	1999	1998
Operating Revenues (in thousands):					
Residential	$1,264,431	$1,138,499	$1,222,509	$1,145,646	$1,133,435
Commercial	882,669	829,760	854,695	807,098	779,169
Industrial	788,037	763,934	859,668	843,090	853,550
Other	16,080	15,480	15,835	15,283	14,523
Total retail	2,951,217	2,747,673	2,952,707	2,811,117	2,780,677
Sales for resale - non-affiliates	474,291	485,974	461,730	415,377	448,973
Sales for resale - affiliates	188,163	245,189	166,219	92,439	103,562
Total revenues from sales of electricity	3,613,671	3,478,836	3,580,656	3,318,933	3,333,212
Other revenues	96,862	107,554	86,805	66,541	53,161
Total	$3,710,533	$3,586,390	$3,667,461	$3,385,474	$3,386,373
Kilowatt-Hour Sales (in thousands):					
Residential	17,402,645	15,880,971	16,771,821	15,699,081	15,794,543
Commercial	13,362,631	12,798,711	12,988,728	12,314,085	11,904,509
Industrial	21,102,568	20,460,022	22,101,407	21,942,889	21,585,117
Other	205,346	198,102	205,827	201,149	196,647
Total retail	52,073,190	49,337,806	52,067,783	50,157,204	49,480,816
Sales for resale - non-affiliates	15,553,545	15,277,839	14,847,533	12,437,599	11,840,910
Sales for resale - affiliates	8,844,050	8,843,094	5,369,474	5,031,781	5,976,099
Total	76,470,785	73,458,739	72,284,790	67,626,584	67,297,825
Average Revenue Per Kilowatt-Hour (cents):					
Residential	7.27	7.17	7.29	7.30	7.18
Commercial	6.61	6.48	6.58	6.55	6.55
Industrial	3.73	3.73	3.89	3.84	3.95
Total retail	5.67	5.57	5.67	5.60	5.62
Sales for resale	2.72	3.03	3.11	2.91	3.10
Total sales	4.73	4.74	4.95	4.91	4.95
Residential Average Annual Kilowatt-Hour Use Per Customer	15,198	13,981	14,875	14,097	14,370
Residential Average Annual Revenue Per Customer	$1,104.28	$1,002.30	$1,084.26	$1,028.76	$1,031.21
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,153	12,153	12,122	11,379	11,151
Maximum Peak-Hour Demand (megawatts):					
Winter	9,423	9,300	9,478	8,863	7,757
Summer	10,910	10,241	11,019	10,739	10,329
Annual Load Factor (percent)	62.9	62.5	59.3	59.7	62.9
Plant Availability (percent):					
Fossil-steam	85.8	87.1	89.4	80.4	85.6
Nuclear	93.2	83.7	88.3	91.0	80.2
Source of Energy Supply (percent):					
Coal	55.5	56.8	63.0	64.1	65.3
Nuclear	17.1	15.8	16.9	17.8	16.3
Hydro	5.1	5.1	2.9	4.7	6.9
Gas	11.6	10.7	4.9	1.1	1.5
Purchased power -					
From non-affiliates	4.0	4.4	4.6	4.5	3.3
From affiliates	6.7	7.2	7.7	7.8	6.7
Total	100.0	100.0	100.0	100.0	100.0

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

David J. Cooper
President,
Cooper/T. Smith Corporation

H. Allen Franklin
Chairman, President and CEO,
Southern Company

R. Kent Henslee
Managing Partner, Henslee, Robertson,
Strawn & Knowles, L.L.C.

Carl E. Jones, Jr.
Chairman, President and CEO,
Regions Financial Corporation

Patricia M. King
President and CEO,
King Motor Company, Inc.

James K. Lowder
Chairman,
The Colonial Company

Wallace D. Malone, Jr.
Chairman and CEO,
SouthTrust Corporation

Charles D. McCrary
President and CEO,
Alabama Power Company

Mayer Mitchell
President, MBI, LLC

Dr. Malcolm Portera [1]
Chancellor, The University of
Alabama System

Robert D. Powers
President, The Eufaula Agency

Andreas Renschler
President, Mcc smart Gmbh

C. Dowd Ritter
Chairman, President and CEO,
AmSouth Bancorporation

James H. Sanford
Chairman, HOME Place Farms, Inc.

Dr. William F. Walker [1]
President, Auburn University

John C. Webb, IV
President, Webb Lumber Company, Inc.

James W. Wright
Chairman and CEO,
First Tuskegee Bank

Officers

Charles D. McCrary
President and Chief Executive Officer

William B. Hutchins, III
Executive Vice President, Chief
Financial Officer and Treasurer

C. Alan Martin
Executive Vice President

Steve R. Spencer
Executive Vice President

Robert Holmes, Jr.
Senior Vice President

Robin A. Hurst
Senior Vice President

Rodney O. Mundy
Senior Vice President and Counsel

Michael L. Scott
Senior Vice President

Jerry L. Stewart
Senior Vice President

Art P. Beattie
Vice President and Comptroller

Willard L. Bowers
Vice President

Christopher T. Bell
Vice President

Marsha S. Johnson
Vice President, Birmingham Division

Gerald L. Johnson
Vice President

William B. Johnson
Vice President

J. Bruce Jones
Vice President

Bobby J. Kerley
Vice President, Southeast Division

William B. Keller [2]
Vice President

Barbara J. Knight [3]
Vice President

Ellen N. Lindemann [4]
Vice President, Human Resources

Penny M. Manuel [5]
Vice President and Chief Information
Officer

Gordon G. Martin
Vice President, Southern Division

Donald W. Reese
Vice President

Julia H. Segars [3]
Vice President and Chief Information
Officer

Julian H. Smith, Jr.
Vice President

W. Ronald Smith
Vice President, Eastern Division

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

William E. Zales, Jr.
Vice President, Corporate Secretary
and Assistant Treasurer

E. Wayne Boston
Assistant Secretary and
Assistant Treasurer

J. Randy DeRieux
Assistant Treasurer

Robert Cole Giddens
Assistant Comptroller

Ceila H. Shorts
Assistant Secretary

Cynthia H. Wilson [6]
Assistant Secretary

Kay I. Worley [7]
Assistant Secretary

[1]Elected 2/03
[2]Retired 6/02
[3]Elected 11/02
[4]Elected 4/02
[5]Resigned 10/02
[6]Resigned 8/02
[7]Appointed 9/02

General
This annual report is submitted for general information and is not intended for use in connection with any sale or purchase of, or any solicitation of offers to buy or sell securities.

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Alabama and to other utilities in the Southeast. The Company sells electricity to 1.4 million customers within its service area of approximately 45,000 square miles. In 2002, retail energy sales accounted for 68 percent of the Company's total sales of 76.5 billion kilowatt-hours.

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities. There is no established public trading market for the Company's common stock.

Trustee, Registrar and Interest Paying Agent
All series of First Mortgage Bonds,
Senior Notes and Trust Preferred Securities
JPMorgan Chase Bank
Institutional Trust Services
4 New York Plaza, 15th Floor
New York, NY 10004

Registrar, Transfer Agent and Dividend Paying Agent
All series except the Flexible Money Market Class A Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

For the Flexible Money Market Class A Preferred Stock
The Bank of New York
101 Barclay Street
New York, NY 10286

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary. For additional information, contact the office of the Corporate Secretary at (205) 257-3385.

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