ORIGINAL

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010949-EI

MINIMUM FILING REQUIREMENTS

SECTION F – MISCELLANEOUS SCHEDULES

GULF POWER

A SOUTHERN COMPANY

ORIGINAL

GULF POWER COMPANY

Docket No. 010949-EI
Minimum Filing Requirements

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F. Miscellaneous Schedules

GULF POWER COMPANY

Docket No. 010949-EI
Minimum Filing Requirements

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F. Miscellaneous Schedules

Schedule F-1 | ANNUAL AND QUARTERLY REPORTS TO SHAREHOLDERS |

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 010949-EI	EXPLANATION: Provide a copy of the most recent Annual Report to Shareholders and all subsequent Quarterly Reports. The company shall file all Quarterly and Annual Reports as they become available during the proceeding.	Type of Data Shown: __ Projected Test Year Ended 5/31/03 __ Prior Year Ended 5/31/02 XX Historical Year 12/31/00 Witness: R. R. Labrato

2000 Annual Report is attached.

Supporting Schedules: Recap Schedules:

2000
Annual Report

GULF POWER
A SOUTHERN COMPANY

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Gulf Power Company 2000 Annual Report

SUMMARY

	2000	1999	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$714,319**	$674,099	6.0
Operating expenses	**$594,438**	$554,937	7.1
Net income after dividends on preferred stock	**$51,843**	$53,667	(3.4)
Gross property additions	**$95,807**	$69,798	37.3
Total assets	**$1,315,496**	$1,308,495	0.5
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**10,112,966**	9,559,183	5.8
Sales for resale - non-affiliates	**1,705,486**	1,561,972	9.2
Sales for resale - affiliates	**1,916,526**	2,511,983	(23.7)
Total	**13,734,978**	13,633,138	0.7
Customers served at year-end	**370,119**	363,551	1.8
Peak-hour demand, net *(in megawatts)*	**2,285**	2,161	5.7
Capitalization Ratios *(percent)*:			
Common stock equity	**48.4**	48.0	0.8
Preferred stock	**0.5**	0.5	0.0
Trust preferred securities	**9.6**	9.7	(1.0)
Long-term debt	**41.5**	41.8	(0.7)
Return on Average Common Equity *(percent)*	**12.20**	12.63	(3.4)

Gulf Power Company had a very successful year in 2000. Our commitment to creating value for our shareholders and our customers is reflected in the Company's strong financial performance, low kilowatt-hour cost, and excellent customer satisfaction ratings.

Gulf Power Company's 2000 net income after dividends on preferred stock was $51.8 million. The return on average common equity for 2000 was 12.20 percent. The Company added 6,568 customers across its service area and sold 13.7 billion kilowatt-hours of electricity. Our rates are still among the lowest in the nation, with the monthly rate for 1,000 kilowatt-hours for residential customers in December 2000 at $64.45.

In its public confidence survey, Gulf Power scored high in customer satisfaction with an 85 percent confidence level. The Company also finished among the top utilities in the nation on a 2000 customer satisfaction survey.

As a result of hotter weather and increased customer growth, our customers received refunds in 2001 as part of the Revenue Sharing Plan approved by the Florida Public Service Commission. The Company's total annual revenues in 2000 were $10.4 million above the revenue sharing threshold of which two-thirds or $6.9 million was refunded to our customers ($7.2 million including interest), and one-third retained by the Company.

Also in 2000, Florida's Governor appointed a 17-member study commission to look at the state's electric industry. The commission's final report and recommendations are due to the Governor and legislature by December 1, 2001. The current federal administration is also addressing similar issues on a national level. These initiatives and other possible changes, which may affect our industry, are discussed more fully within this report.

At Gulf Power, our goal is to provide reliable, low cost service and superior customer satisfaction. Thank you for your continued support and confidence.

Sincerely,

Travis A. Bowden

Travis Bowden
President and Chief Executive Officer
March 31, 2001

The management of Gulf 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 audit committee of the board of directors, composed of independent directors provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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 Gulf Power Company in conformity with accounting principles generally accepted in the United States.

Travis J. Bowden
President
and Chief Executive Officer

Ronnie R. Labrato
Comptroller
and Chief Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Gulf Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (a Maine corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2000 and 1999, 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, 2000. 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 14 - 28) referred to above present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Gulf Power Company's 2000 net income after dividends on preferred stock was $51.8 million, a decrease of $1.9 million from the previous year. In 1999, earnings were $53.7 million, down $2.8 million when compared to 1998. The decrease in earnings in 2000, as well as 1999, was primarily a result of higher expenses than in the prior year.

Revenues

Operating revenues increased in 2000 when compared to 1999. The following table summarizes the change in operating revenues for the past two years:

	Amount	Increase (Decrease) From Prior Year	
	2000	**2000**	1999
		(in thousands)	
Retail --			
Base Revenues	**$336,103**	$3,771	$2,469
Regulatory cost recovery and other	**226,059**	45,631	1,173
Total retail	**562,162**	49,402	3,642
Sales for resale--			
Non-affiliates	**66,890**	4,537	461
Affiliates	**66,995**	885	23,468
Total sales for resale	**133,885**	5,422	23,929
Other operating revenues	**18,272**	(14,604)	(3,990)
Total operating revenues	**$714,319**	$40,220	$23,581
Percent change		6.0%	3.6%

Retail revenues of $562.2 million in 2000 increased $49.4 million, or 9.6 percent, from the prior year due primarily to the recovery of higher fuel and purchased power costs. Retail base rate revenues increased $3.8 million due to increased customer growth and hotter than normal weather, offset by a $10 million permanent annual rate reduction and $6.9 million of revenues subject to refund based upon the current retail revenue sharing plan (See Note 3 to the financial statements under "Retail Revenue Sharing Plan" for further information). Retail revenues for 1999 increased $3.6 million, or 0.7 percent, when compared to 1998 due primarily to an increase in the number of retail customers served by the Company.

The 2000 increase in regulatory cost recovery and other retail revenues over 1999 is primarily attributable to higher fuel and purchased power costs. The 1999 increase in regulatory cost recovery and other retail revenues over 1998 is primarily attributable to the recovery of increased purchased power capacity costs. "Regulatory cost recovery and other" includes the following: recovery provisions for fuel expense and the energy component of purchased power costs; energy conservation costs; purchased power capacity costs; and environmental compliance costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further information.

Sales for resale were $133.9 million in 2000, an increase of $5.4 million, or 4.2 percent, over 1999 primarily due to additional energy sales. Revenues from sales to utilities outside the service area under long-term contracts consist of capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components under these long-term contracts were as follows:

	2000	1999	1998
		(in thousands)	
Capacity	**$20,270**	$19,792	$22,503
Energy	**21,922**	20,251	14,556
Total	**$42,192**	$40,043	$37,059

Capacity revenues increased slightly in 2000 due to the recovery of higher operating expenses experienced during the year. Capacity revenues had been declining in prior years due to the decreasing net investment related to these sales. This downward trend accelerated during 1999 as a result of a reduction in the authorized rate of return on the equity component of the investment.

Sales to affiliated companies vary from year to year depending on demand and the availability and cost of generating resources at each company. These sales have little impact on earnings.

Other operating revenues decreased in 2000 and in 1999 due primarily to the retail recovery clause adjustments for the difference between recoverable costs and the amounts actually reflected in current rates. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further discussion.

Energy Sales

Kilowatt-hour sales for 2000 and the percent changes by year were as follows:

	KWH	Percent Change	
	2000	**2000**	1999
	(millions)		
Residential	**4,790**	**7.1%**	0.8%
Commercial	**3,379**	**4.9**	3.6
Industrial	**1,925**	**4.3**	0.7
Other	**19**	**0.0**	0.0
Total retail	**10,113**	**5.8**	1.7
Sales for resale			
Non-affiliates	**1,705**	**9.2**	16.4
Affiliates	**1,917**	**(23.7)**	42.9
Total	**13,735**	**0.7**	9.0

In 2000, total retail energy sales increased when compared to 1999 due primarily to an increase in the total number of customers and hotter than normal weather. Total retail energy sales increased in 1999 when compared to 1998 due to increases in the number of customers. See "Future Earnings Potential" for information on the Company's initiatives to remain competitive and to meet conservation goals set by the Florida Public Service Commission (FPSC).

An increase in energy sales for resale to non-affiliates of 9.2 percent in 2000 when compared to 1999 is primarily related to unit power sales under long-term contracts to other Florida utilities and bulk power sales under short-term contracts to other non-affiliated utilities. Energy sales to affiliated companies vary from year to year depending on demand and availability and cost of generating resources at each company.

Expenses

Total operating expenses in 2000 increased $39.5 million, or 7.1 percent, over the amount recorded in 1999 due primarily to higher fuel and purchased power expenses. In 1999, total operating expenses increased $26.8 million, or 5.1 percent, compared to 1998 due primarily to higher fuel, purchased power, and maintenance expenses offset by lower other operation expenses.

Fuel expenses in 2000, when compared to 1999, increased $6.7 million, or 3.2 percent, due primarily to an increase in average fuel costs. In 1999, fuel expenses increased $11.5 million, or 5.9 percent, when compared to 1998. The increases were the result of increased generation resulting from a higher demand for energy.

The amount and sources of generation and the average cost of fuel per net kilowatt-hour generated were as follows:

	2000	1999	199[illegible]
Total generation (millions of kilowatt-hours)	**12,866**	13,095	11,98[illegible]
Sources of generation (percent)			
Coal	**98.2**	97.4	98.[illegible]
Oil and gas	**1.8**	2.6	2.[illegible]
Average cost of fuel per net kilowatt-hour generated (cents)--	**1.68**	1.60	1.6[illegible]

Purchased power expenses increased in 2000 by $25.5 million, or 44.7 percent, over 1999 and purchased power expenses for 1999 increased over 1998 by $13.2 million, or 30.2 percent, due primarily to a higher demand for energy in both years.

Depreciation and amortization expense increased $2.3 million, or 3.5 percent, in 2000 when compared to 1999, due to an increase in depreciable property and the amortization of a portion of a regulatory asset, which was allowed in the current retail revenue sharing plan. The $5.5 million, or 9.2 percent, increase in 1999 compared to 1998 was due primarily to a reduction in the amortization of gains from the 1998 sale of emission allowances.

Interest on long-term debt, which is included in "Interest expense", increased $1.2 million, or 5.8 percent, in 2000 when compared to 1999 due primarily to the issuance of $50 million of senior notes in August 1999. In 1999 interest on long-term debt increased $1.7 million, or 8.4 percent, when compared to 1998 due primarily to the maturity of two first mortgage bond series in 1998 which were replaced by senior notes at a slightly higher interest rate, and the issuance of $50 million of senior notes in August 1999.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of historical costs. Therefore, inflation creates an economic loss because the Company is recovering its cost 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.

Future Earnings Potential

The results of 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 to achieve energy sales growth while containing cost in a more competitive environment.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $5.8 million in 2000. Pension income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in northwest Florida. Prices for electricity provided by the Company to retail customers are set by the FPSC.

Future earnings in the near term will depend upon growth in energy sales, which is subject to a number of factors. Traditionally, these factors have included weather, competition, changes in 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. In early 1999, the FPSC staff and the Company became involved in discussions primarily related to reducing the Company's authorized rate of return. On October 1, 1999, the Office of Public Counsel, the Coalition for Equitable Rates, the Florida Industrial Power Users Group, and the Company jointly filed a petition to resolve the issues. The stipulation included a reduction to retail base rates of $10 million annually and provides for revenues to be shared within set ranges for 1999 through 2002. Customers receive two-thirds of any revenue within the sharing range and the Company retains one-third. Any revenue above this range is refunded to the customers. The stipulation also included authorization for the Company, at its discretion, to accrue up to an additional $5 million to the property insurance reserve and $1 million to amortize a regulatory asset related to the corporate office. The Company also filed a request to prospectively reduce its authorized ROE range from 11 to 13 percent to 10.5 to 12.5 percent in order to help ensure that the FPSC would approve the stipulation. The FPSC approved both the stipulation and the ROE request with an effective date of November 4, 1999. The Company is currently planning to seek additional rate relief to recover costs related to the Smith Unit 3 combined cycle facility currently under construction and scheduled to be placed in-service in June of 2002.

For calendar year 2000, the Company's retail revenue range for sharing was $352 million to $368 million. Actual retail revenues in 2000 were $362.4 million and the Company recorded revenues subject to refund of $6.9 million. The estimated refund with interest was reflected in customer billings in February 2001. For calendar year 2001, the Company's retail revenue range for sharing is $358 million to $374 million. For calendar year 2002, there are specified sharing ranges for each month from the expected in-service date of Smith Unit 3 until the end of the year. The sharing plan will expire at the earlier of the in-service date of Smith Unit 3 or December 31, 2002.

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 cogeneration plants for a utility's large industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are being driven down by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers. The Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets.

In 2000, Florida's Governor appointed a 17 member study commission to look at the state's electric industry, studying issues ranging from current and future reliability of electric and natural gas supply, electric industry retail and wholesale competition, environmental impacts of energy supply, conservation, and tax issues. The commission's final report and recommendations are due to the Governor and legislature by December 1, 2001. The commission submitted an interim report to the state legislature that involves introducing more competition into the wholesale production of electricity in Florida. If approved by the legislature, the proposal would require utilities to turn over generating assets to an unregulated affiliate company over a 6-year transition period. The proposal would allow out of state companies to build merchant facilities and to bid on new generation needs. The effects of any proposed changes cannot presently be determined, but could have a material effect on the Company's financial statements.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers 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 Florida, none have been enacted. Enactment 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 current energy crisis in California. As a result of this crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The inability of a company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on financial condition and results of operations.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. 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.

In 1996, the FPSC approved a new optional Commercial/Industrial Service Rider (CISR), which is applicable to the rate schedules for the Company's largest existing and potential customers who are able to show they have viable alternatives to purchasing the Company's energy services. The CISR, approved as a pilot program, provides the flexibility needed to enable the Company to offer its services in a more competitive manner to these customers. The publicity of the CISR ruling, increased competitive pressures, and general awareness of customer choice pilots and proposals across the country have stimulated interest on the part of customers in custom tailored offerings. The Company has participated in one-on-one discussions with many of these customers, and has negotiated and executed two Contract Service Agreements within the CISR pilot program. The pilot program was scheduled to end in 2000; however, on February 6, 2001 the FPSC approved the Company's request to remove the original 48 month limitation and allow the program to continue.

Every five years the FPSC establishes numeric demand side management goals. The Company proposed numeric goals for the ten-year period from 2000 to 2009. The proposed goals consisted of the total, cost-effective winter and summer peak demand (kilowatts) and annual energy (kilowatt-hour) savings reasonably achievable from demand side management for the residential and commercial/industrial classes. The Company submitted its 2001 Demand Side Management Plan to the FPSC on December 29, 2000. The plan describes the proposed programs the Company will employ to reach the numeric goals. The plan relies heavily on innovative pricing and energy efficient construction.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. Southern Company and its integrated utility subsidiaries, including the Company, filed on October 16, 2000, a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of the Company and any other participating utilities. Participants would have the option to either maintain their ownership or divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on the Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUHCA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUHCA. These entities are able to own and operate power generating facilities and sell power to affiliates -- under certain restrictions.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary -- Southern Power Company. The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. Southern Power will be the primary growth engine for Southern Company's market-based energy business. Energy from its assets will be marketed to wholesale customers under the Southern Company name.

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." Also, Florida legislation adopted in 1993 that provides for recovery of prudent environmental compliance costs is discussed in Note 3 to the financial statements under "Environmental Cost Recovery."

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 operations 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.

Exposure to Market Risks

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates 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. Realized gains and losses are recognized in the income statements as incurred. At December 31, 2000, exposure from these activities was not material.

New Accounting Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

The Company may utilize financial instruments to reduce its exposure to changes in interest rates depending on market conditions. The Company also enters into commodity related forward contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales.

Substantially all of these bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted Statement No. 133 effective January 1, 2001. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from FASB is expected, which could additionally impact the Company's financial statements. Also, as wholesale energy markets mature, future transactions could result in more volatility in net income and comprehensive income.

Financial Condition

Overview

The Company's financial condition continues to be very solid. During 2000, gross property additions were $95.8 million. Funds for the property additions were provided by operating activities. See the Statements of Cash Flows for further details.

Financing Activities

In 2000, there were no issuances or retirements of long-term debt. In 1999, the Company sold $50 million of senior notes and long-term bank notes totaling $27 million were retired. See the Statements of Cash Flows for further details.

Composite financing rates for the years 1998 through 2000 as of year end were as follows:

	2000	1999	1998
Composite interest rate on long-term debt	**6.2%**	6.0%	6.1%
Composite rate on trust preferred securities	**7.3%**	7.3%	7.3%
Composite preferred stock dividend rate	**5.1%**	5.1%	5.1%

The composite interest rate on long-term debt increased in 2000 due to higher interest rates on variable rate pollution control bonds.

Capital Requirements for Construction

The Company's gross property additions, including those amounts related to environmental compliance, are budgeted at $451 million for the three years beginning in 2001 ($279 million in 2001, $96 million in 2002, and $76 million in 2003). These amounts include $199.2 million for the years 2001 and 2002 for the estimated cost of a 574 megawatt combined cycle gas generating unit and related interconnections to be located in the eastern portion of the Company's service area. The unit is expected to have an in-service date of June 2002. The remaining property additions budget is primarily for maintaining and upgrading transmission and distribution facilities and generating plants. Actual construction costs may vary from this estimate because of changes in such factors as the following: business conditions; environmental 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

The Company will continue to retire higher-cost debt and preferred securities and replace these securities with lower-cost capital as market conditions and terms of the instruments permit.

Environmental Matters

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) was signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected the Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995. As a result of a systemwide compliance strategy, some 50 generating units of Southern Company were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions compliance totaled approximately $300 million for Southern Company, including approximately $42 million for the Company.

Phase II sulfur dioxide compliance was required in 2000. Southern Company used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased Southern Company's total construction expenditures through 2000 by approximately $100 million. Phase II compliance did not have a material impact on Gulf Power.

A significant portion of costs related to the acid rain and ozone nonattainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In 1993, the Florida Legislature adopted legislation that allows a utility to petition the FPSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the Environmental Cost Recovery Clause.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rule to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Georgia. See Note 5 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3.

In December 2000, the EPA completed its utility study for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls will likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are also reviewing and evaluating various other matters including: nitrogen oxide emission control strategies for ozone non-attainment areas; additional controls for hazardous air pollutant emissions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

On November 3, 1999, the EPA brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 5 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in

Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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 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.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. 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 costs and has recognized in the financial statements costs to clean up known sites. For additional information, see Note 3 to the financial statements under "Environmental Cost Recovery."

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electric and magnetic fields, and other environmental health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electric and magnetic fields.

Sources of Capital

At December 31, 2000, the Company had approximately $4.4 million of cash and cash equivalents and $53.5 million of unused committed lines of credit with banks to meet its short-term cash needs. Refer to the Statements of Cash Flows for details related to the Company's financing activities. See Note 4 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company historically has relied on issuances of first mortgage bonds and preferred stock, in addition to pollution control revenue bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. Recently, the Company's financings have consisted of unsecured debt and trust preferred securities. The Company has no restrictions on the amounts of unsecured indebtedness it may incur. However, in order to issue first mortgage bonds or preferred stock, the Company is required to meet certain coverage requirements specified in its mortgage indenture and corporate charter. The Company's ability to satisfy all coverage requirements is such that it could issue new first mortgage bonds and preferred stock to provide sufficient funds for all anticipated requirements.

Cautionary Statement Regarding Forward-Looking Information

The Company's 2000 Annual Report contains forward looking and historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "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; the extent and timing of the entry of additional competition in the markets of the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the registrants; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME

For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$562,162**	$512,760	$509,118
Sales for resale --			
Non-affiliates	**66,890**	62,354	61,893
Affiliates	**66,995**	66,110	42,642
Other revenues	**18,272**	32,875	36,865
Total operating revenues	**714,319**	674,099	650,518
Operating Expenses:			
Operation --			
Fuel	**215,744**	209,031	197,462
Purchased power --			
Non-affiliates	**73,846**	46,332	29,369
Affiliates	**8,644**	10,703	14,445
Other	**117,146**	114,670	119,011
Maintenance	**56,281**	57,830	57,286
Depreciation and amortization	**66,873**	64,589	59,129
Taxes other than income taxes	**55,904**	51,782	51,462
Total operating expenses	**594,438**	554,937	528,164
Operating Income	**119,881**	119,162	122,354
Other Income (Expense):			
Interest income	**1,137**	1,771	931
Other, net	**(4,126)**	(1,357)	(2,339)
Earnings Before Interest and Income Taxes	**116,892**	119,576	120,946
Interest and Other:			
Interest expense, net	**28,085**	26,861	25,556
Distributions on preferred securities of subsidiary	**6,200**	6,200	6,034
Total interest charges and other, net	**34,285**	33,061	31,590
Earnings Before Income Taxes	**82,607**	86,515	89,356
Income taxes (Note 7)	**30,530**	32,631	32,199
Net Income	**52,077**	53,884	57,157
Dividends on Preferred Stock	**234**	217	636
Net Income After Dividends on Preferred Stock	**$ 51,843**	$ 53,667	$ 56,521

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	$ **52,077**	$ 53,884	$ 57,157
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**69,915**	68,721	69,633
Deferred income taxes and investment tax credits, net	**(12,516)**	(6,609)	(4,684)
Other, net	**10,686**	3,735	3,463
Changes in certain current assets and liabilities --			
Receivables, net	**(20,212)**	(10,484)	11,308
Fossil fuel stock	**13,101**	(5,656)	(4,917)
Materials and supplies	**1,055**	(2,063)	609
Accounts payable	**15,924**	(2,023)	823
Provision for rate refund	**7,203**	-	-
Other	**12,521**	7,030	(18,471)
Net cash provided from operating activities	**149,754**	106,535	114,921
Investing Activities:			
Gross property additions	**(95,807)**	(69,798)	(69,731)
Other	**(4,432)**	(8,856)	5,990
Net cash used for investing activities	**(100,239)**	(78,654)	(63,741)
Financing Activities:			
Increase (decrease) in notes payable, net	**(12,000)**	23,500	(15,500)
Proceeds --			
Other long-term debt	**-**	50,000	50,000
Preferred securities	**-**	-	45,000
Capital contributions from parent company	**12,222**	2,294	522
Retirements --			
First mortgage bonds	**-**	-	(45,000)
Other long-term debt	**(1,853)**	(27,074)	(8,326)
Preferred stock	**-**	-	(9,455)
Payment of preferred stock dividends	**(234)**	(271)	(792)
Payment of common stock dividends	**(59,000)**	(61,300)	(67,200)
Other	**(22)**	(246)	(4,167)
Net cash used for financing activities	**(60,887)**	(13,097)	(54,918)
Net Change in Cash and Cash Equivalents	**(11,372)**	14,784	(3,738)
Cash and Cash Equivalents at Beginning of Period	**15,753**	969	4,707
Cash and Cash Equivalents at End of Period	$ **4,381**	$ 15,753	$ 969
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$32,277**	$27,670	$28,044
Income taxes (net of refunds)	**42,252**	29,462	38,782

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

Assets	2000	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 4,381**	$ 15,753
Receivables --		
Customer accounts receivable	**69,820**	55,108
Other accounts and notes receivable	**2,179**	4,325
Affiliated companies	**15,026**	7,104
Accumulated provision for uncollectible accounts	**(1,302)**	(1,026)
Fossil fuel stock, at average cost	**16,768**	29,869
Materials and supplies, at average cost	**29,033**	30,088
Regulatory clauses under recovery	**2,112**	11,611
Other	**6,543**	5,354
Total current assets	**144,560**	158,186
Property, Plant, and Equipment:		
In service	**1,892,023**	1,853,664
Less accumulated provision for depreciation	**867,260**	821,970
	1,024,763	1,031,694
Construction work in progress	**71,008**	34,164
Total property, plant, and equipment	**1,095,771**	1,065,858
Other Property and Investments	**4,510**	1,481
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 7)	**15,963**	25,264
Prepaid pension costs (Note 2)	**23,491**	17,734
Debt expense, being amortized	**2,392**	2,526
Premium on reacquired debt, being amortized	**15,866**	17,360
Other	**12,943**	20,086
Total deferred charges and other assets	**70,655**	82,970
Total Assets	**$1,315,496**	$1,308,495

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	2000	1999
	(in thousands)	
Current Liabilities:		
Notes payable	$ 43,000	$ 55,000
Accounts payable --		
Affiliated	17,558	14,878
Other	38,153	22,581
Customer deposits	13,474	12,778
Taxes accrued --		
Income taxes	3,864	4,889
Other	8,749	7,707
Interest accrued	8,324	9,255
Provision for rate refund	7,203	-
Vacation pay accrued	4,512	4,199
Regulatory clauses over recovery	6,848	3,125
Other	1,584	1,836
Total current liabilities	153,269	136,248
Long-term debt (See accompanying statements)	365,993	367,449
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 7)	155,074	162,776
Deferred credits related to income taxes (Note 7)	38,255	49,693
Accumulated deferred investment tax credits	25,792	27,712
Employee benefits provisions	34,507	31,735
Other	25,992	21,333
Total deferred credits and other liabilities	279,620	293,249
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	85,000	85,000
Preferred stock (See accompanying statements)	4,236	4,236
Common stockholder's equity (See accompanying statements)	427,378	422,313
Total Liabilities and Stockholder's Equity	$1,315,496	$1,308,495

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

		2000	1999	2000	1999
		(in thousands)		*(percent of total)*	
Long Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
July 1, 2003	6.125%	**$ 30,000**	$ 30,000		
November 1, 2006	6.50%	**25,000**	25,000		
January 1, 2026	6.875%	**30,000**	30,000		
Total first mortgage bonds		**85,000**	85,000		
Long-term notes payable --					
7.50% due June 30, 2037		**20,000**	20,000		
6.70% due June 30, 2038		**48,073**	49,926		
7.05% due August 15, 2004		**50,000**	50,000		
Total long-term notes payable		**118,073**	119,926		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.25% to 6.30% due 2006-2026		**108,700**	108,700		
Variable rates (3.70% at 1/1/00) due 2024		**-**	20,000		
Non-collateralized:					
Variable rates (5.10% to 5.30% at 1/1/01) due 2022-2024		**60,930**	40,930		
Total other long-term debt		**169,630**	169,630		
Unamortized debt premium (discount), net		**(6,710)**	(7,107)		
Total long-term debt (annual interest requirement -- $23.2 million)		**365,993**	367,449	**41.5%**	41.8%
Cumulative Preferred Stock:					
$100 par value, 4.64% to 5.44%		**4,236**	4,236		
Total (annual dividend requirement -- $0.2 million)		**4,236**	4,236	**0.5%**	0.5%
Company Obligated Mandatorily Redeemable Preferred Securities:					
$25 liquidation value --					
7.00%		**45,000**	45,000		
7.63%		**40,000**	40,000		
Total (annual distribution requirement -- $6.2 million)		**85,000**	85,000	**9.6%**	9.7%
Common Stockholder's Equity:					
Common stock, without par value --					
Authorized and outstanding - 992,717 shares in 2000 and 1999		**38,060**	38,060		
Paid-in capital		**233,476**	221,254		
Premium on preferred stock		**12**	12		
Retained earnings		**155,830**	162,987		
Total common stockholder's equity		**427,378**	422,313	**48.4%**	48.0%
Total Capitalization		**$882,607**	$878,998	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1998	$38,060	$218,438	$12	$172,208	$428,718
Net income after dividends on preferred stock	-	-	-	56,521	56,521
Capital contributions from parent company	-	522	-	-	522
Cash dividends on common stock	-	-	-	(57,200)	(57,200)
Other	-	-	-	(909)	(909)
Balance at December 31, 1998	38,060	218,960	12	170,620	427,652
Net income after dividends on preferred stock	-	-	-	53,667	53,667
Capital contributions from parent company	-	2,294	-	-	2,294
Cash dividends on common stock	-	-	-	(61,300)	(61,300)
Balance at December 31, 1999	38,060	221,254	12	162,987	422,313
Net income after dividends on preferred stock	-	-	-	**51,843**	**51,843**
Capital contributions from parent company	-	**12,222**	-	-	**12,222**
Cash dividends on common stock	-	-	-	**(59,000)**	**(59,000)**
Balance at December 31, 2000	**$38,060**	**$233,476**	**$12**	**$155,830**	**$427,378**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, Southern Company Services (SCS), Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Mirant Corporation (Mirant) – formerly Southern Energy, Inc., -- Southern Nuclear Operating Company (Southern Nuclear), and other direct and indirect subsidiaries. The integrated Southeast utilities -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four states. Gulf Power Company provides electric service to the northwest panhandle of Florida. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power --are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). The system service company provides, at cost, specialized services to Southern Company and 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 Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

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 Florida Public Service Commission (FPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the FPSC and the FERC. 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.

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, 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 operations. Costs for these services amounted to $44 million, $43 million, and $40 million during 2000, 1999, and 1998, respectively.

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 to the Company 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:

	2000	1999
	(in thousands)	
Deferred income tax charges	**$15,963**	$25,264
Deferred loss on reacquired debt	**15,866**	17,360
Environmental remediation	**7,638**	5,745
Vacation pay	**4,512**	4,199
Regulatory clauses under (over) recovery, net	**(4,736)**	8,486
Accumulated provision for rate refunds	**(7,203)**	-
Accumulated provision for property damage	**(8,731)**	(5,528)
Deferred income tax credits	**(38,255)**	(49,693)
Other, net	**(1,074)**	(1,255)
Total	**$(16,020)**	$ 4,578

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 any impairment to other assets, including plant, and write down the assets, if impaired, to their fair value.

Revenues and Regulatory Cost Recovery Clauses

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its service area located in northwest Florida 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. The Company's retail electric rates include provisions to annually adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company also has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted monthly for differences between recoverable costs and amounts actually reflected in current rates.

The Company has a diversified base of customers and no single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged significantly less than 1 percent of revenues.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.8 percent in 2000, 1999, and 1998. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost -- together with the cost of removal, less salvage -- is charged to the accumulated provision for depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Also, the provision for depreciation expense includes an amount for the expected cost of removal of facilities.

Income Taxes

The Company uses the liability method of accounting for 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. The Company is included in the consolidated federal income tax return of Southern Company.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. 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 maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property (exclusive of minor items of property) is charged to utility plant.

Cash and Cash Equivalents

Temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Financial Instruments

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

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
At December 31, 2000	**$365,993**	**$364,697**
At December 31, 1999	$367,449	$349,791
Capital trust preferred securities:		
At December 31, 2000	**$85,000**	**$80,988**
At December 31, 1999	$85,000	$69,092

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

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.

Provision for Injuries and Damages

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by regulatory authorities, the Company provides for the uninsured costs of injuries and damages by charges to income amounting to $1.2 million annually. The expense of settling claims is charged to the provision to the extent available. The accumulated provision of $1.2 million and $1.8 million at December 31, 2000 and 1999, respectively, is included in other current liabilities in the accompanying Balance Sheets.

Provision for Property Damage

The Company provides for the cost of repairing damages from major storms and other uninsured property damages. This includes the full cost of major storms and other damages to its transmission and distribution lines and the cost of uninsured damages to its generation and other property. The expense of such damages is charged to the provision account. At December 31, 2000 and 1999, the accumulated provision for property damage was $8.7 million and $5.5 million, respectively. The FPSC approved annual accrual to the accumulated provision for property damage is $3.5 million, with a target level for the accumulated provision account between $25.1 and $36.0 million. The FPSC has also given the Company the flexibility to increase its annual accrual amount above $3.5 million at the Company's discretion. The Company accrued $3.5 million in 2000, $5.5 million in 1999, and $6.5 million in 1998 to the accumulated provision for property damage. The Company charged $0.3 million, $1.6 million, and $4.2 million against the provision account in 2000, 1999, and 1998 respectively.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, non-contributory pension plan that covers substantially all regular employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits when they retire. Trusts are funded to the extent required by the Company's regulatory commissions. In late 2000, the Company adopted several pension and postretirement benefit plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase the Company's annual pension and postretirement benefits costs by approximately $1.2 million and $0.6 million, respectively. The measurement date for plan assets and obligations is September 30 for each year.

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$141,967**	$143,012
Service cost	**4,282**	4,490
Interest cost	**10,394**	9,440
Benefits paid	**(6,973)**	(6,862)
Actuarial gain and employee transfers, net	**(689)**	(8,113)
Balance at end of year	**$148,981**	$141,967

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$241,485**	$212,934
Actual return on plan assets	**43,833**	35,971
Benefits paid	**(6,973)**	(6,862)
Employee transfers	**4,921**	(558)
Balance at end of year	**$283,266**	$241,485

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

	2000	1999
	(in thousands)	
Funded status	**$134,286**	$99,518
Unrecognized transition obligation	**(3,602)**	(4,323)
Unrecognized prior service cost	**4,121**	4,495
Unrecognized net gain	**(111,314)**	(81,956)
Prepaid asset recognized in the Balance Sheets	**$ 23,491**	$17,734

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

	2000	1999	1998
Service cost	**$4,282**	$4,490	$ 4,107
Interest cost	**10,394**	9,440	9,572
Expected return on plan assets	**(17,504)**	(15,968)	(14,827)
Recognized net gain	**(2,582)**	(1,579)	(1,891)
Net amortization	**(347)**	(347)	(347)
Net pension income	**$(5,757)**	$(3,964)	$(3,386)

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$48,010**	$49,303
Service cost	**896**	1,087
Interest cost	**3,515**	3,261
Benefits paid	**(1,462)**	(1,177)
Actuarial gain and employee transfers, net	**(934)**	(4,464)
Balance at end of year	**$50,025**	$48,010

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$11,196**	**$ 9,603**
Actual return on plan assets	**2,079**	**1,525**
Employer contributions	**1,575**	**1,245**
Benefits paid	**(1,462)**	**(1,177)**
Balance at end of year	**$13,388**	**$11,196**

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

	2000	1999
	(in thousands)	
Funded status	**$ (36,638)**	**$ (36,814)**
Unrecognized transition obligation	**4,368**	**4,723**
Unrecognized prior service cost	**2,582**	**2,741**
Unrecognized net loss	**496**	**2,620**
Fourth quarter contributions	**316**	**300**
Accrued liability recognized in the Balance Sheets	**$(28,876)**	**$(26,430)**

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

	2000	1999	1998
Service cost	**$ 896**	$ 1,087	$ 946
Interest cost	**3,515**	3,261	3,123
Expected return on plan assets	**(901)**	(794)	(717)
Transition obligation	**355**	356	356
Prior service cost	**159**	159	119
Recognized net loss	**13**	264	128
Net postretirement cost	**$ 4,037**	$ 4,333	$3,955

The weighted average rates assumed in the actuarial calculations for both the pension plan and postretirement benefits were:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00%**	5.00%
Long-term return on plan assets	**8.50%**	8.50%

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.3 percent for 2000, decreasing gradually to 5.5 percent through the year 2005, 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, 2000 as follows (in thousands):

	1 Percent Increase	1 Percent Decrease
Benefit obligation	$3,187	$2,874
Service and interest costs	$278	$247

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 2000, 1999, and 1998 were $2.2 million, $2.0 million, and $2.0 million, respectively.

Work Force Reduction Programs

The Company recorded costs related to work force reduction programs of $0.6 million in 2000, $0.2 million in 1999, and $2.8 million in 1998. The Company has also incurred its pro rata share for the costs of affiliated companies' programs. The costs related to these programs were $1.2 million for 2000, $0.6 million for 1999, and $0.2 million for 1998. The Company has expensed all costs related to these work force reduction programs.

3. CONTINGENCIES AND REGULATORY MATTERS

Environmental Cost Recovery

In 1993, the Florida Legislature adopted legislation for an Environmental Cost Recovery Clause (ECRC), which allows a utility to petition the FPSC for recovery of all prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital.

In 1994, the FPSC approved the Company's initial petition under the ECRC for recovery of environmental costs. During 2000, 1999, and 1998, the Company recorded ECRC revenues of $9.9 million, $11.5 million, and $8.0 million, respectively.

At December 31, 2000, the Company's liability for the estimated costs of environmental remediation projects for known sites was $7.6 million. These estimated costs are expected to be expended from 2001 through 2006. These projects have been approved by the FPSC for recovery through the ECRC discussed above. Therefore, the Company recorded $1.2 million in current assets and current liabilities and $6.4 million in deferred assets and deferred liabilities representing the future recoverability of these costs.

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and SCS. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 5 under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. The Company believes that its integrated utilities 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 Revenue Sharing Plan

In early 1999, the FPSC staff and the Company became involved in discussions primarily related to reducing the Company's authorized rate of return. On October 1, 1999, the Office of Public Counsel, the Coalition for Equitable Rates, the Florida Industrial Power Users Group, and the Company jointly filed a petition to resolve the issues. The stipulation included a reduction to retail base rates of $10 million annually and provides for revenues to be shared within set ranges for 1999 through 2002. Customers receive two-thirds of any revenue within the sharing range and the Company retains one-third. Any revenue above this range is refunded to the customers. The stipulation also included authorization for the Company, at its discretion, to accrue up to an additional $5 million to the property insurance reserve and $1 million to amortize a regulatory asset related to the corporate office. The Company also filed a request to prospectively reduce its authorized ROE range from 11 to 13 percent to 10.5 to 12.5 percent in order to help ensure that the FPSC would approve the stipulation. The FPSC approved both the stipulation and the ROE request with an effective date of November 4, 1999. The Company is currently planning to seek additional rate relief to recover costs related to the Smith Unit 3 combined cycle facility scheduled to be placed in-service in June of 2002.

For calendar year 2000, the Company's retail revenue range for sharing was $352 million to $368 million to be shared between the Company and its retail customers on the one-third/two-thirds basis. Actual retail revenues in 2000 were $362.4 million and the Company recorded revenues subject to refund of $6.9 million. The estimated refund with interest of $0.3 million was reflected in customer billings in February 2001. In addition to the refund the Company amortized $1 million of the regulatory assets related to the corporate office. For calendar year 2001, the Company's retail revenue range for sharing is $358 million to $374 million. For calendar year 2002, there are specified sharing ranges for each month from the expected in-service date of Smith Unit 3 until the end of the year. The sharing plan will expire at the earlier of the in-service date of Smith Unit 3 or December 31, 2002.

4. FINANCING AND COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $279 million in 2001, $96 million in 2002, and $76 million in 2003. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; revised load growth estimates; changes in environmental regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2000, significant purchase commitments were outstanding in connection with the construction program. The Company has budgeted $199.2 million for the years 2001 and 2002 for the estimated cost of a 574 megawatt combined cycle gas generating unit to be located in the eastern portion of its service area. The unit is expected to have an in-service date of June 2002. The Company's remaining construction program is related to maintaining and upgrading the transmission, distribution, and generating facilities.

Bank Credit Arrangements

At December 31, 2000, the Company had $61.5 million of lines of credit with banks subject to renewal June 1 of each year, of which $53.5 million remained unused. In addition, the Company has two unused committed lines of credit totaling $61.9 million that were established for liquidity support of its variable rate pollution control bonds. In connection with these credit lines, the Company has agreed to pay commitment fees and/or to maintain compensating balances with the banks. The compensating balances, which represent substantially all of the cash of the Company except for daily working funds and like items, are not legally restricted from withdrawal. In addition, the Company has bid-loan facilities with seven major money center banks that total $130 million, of which $35 million was committed at December 31, 2000.

Assets Subject to Lien

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

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into contract commitments for the procurement of fuel. In some cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated obligations at December 31, 2000 were as follows:

Year	Fuel
	(in millions)
2001	$139
2002	91
2003	90
2004	92
2005	93
2006-2024	473
Total commitments	$978

Lease Agreements

In 1989, the Company and Mississippi Power jointly entered into a twenty-two year operating lease agreement for the use of 495 aluminum railcars. In 1994, a second lease agreement for the use of 250 additional aluminum railcars was entered into for twenty-two years. Both of these leases are for the transportation of coal to Plant Daniel. At the end of each lease term, the Company has the option to renew the lease. In 1997, three additional lease agreements for 120 cars each were entered into for three years, with a monthly renewal option for up to an additional nine months.

The Company, as a joint owner of Plant Daniel, is responsible for one half of the lease costs. The lease costs are charged to fuel inventory and are allocated to fuel expense as the fuel is used. The Company's share of the lease costs charged to fuel inventories was $2.1 million in 2000 and $2.8 million in 1999. The annual amounts for 2001 through 2005 are expected to be $1.9 million, $1.9 million, $1.9 million, $2.0 million, and $2.0 million, respectively, and after 2005 are expected to total $13.8 million.

5. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel, a steam-electric generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of the plant.

The Company and Georgia Power jointly own Plant Scherer Unit No. 3. Plant Scherer is a steam-electric generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's pro rata share of expenses related to both plants is included in the corresponding operating expense accounts in the Statements of Income.

At December 31, 2000, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit No. 3 (coal-fired)	Plant Daniel (coal-fired)
	(in thousands)	
Plant In Service	**$185,778(1)**	**$232,074**
Accumulated Depreciation	**$70,207**	**$118,504**
Construction Work in Progress	**$252**	**$2,006**
Nameplate Capacity (2) (megawatts)	**205**	**500**
Ownership	**25%**	**50%**

(1) Includes net plant acquisition adjustment.
(2) Total megawatt nameplate capacity:
Plant Scherer Unit No. 3: 818
Plant Daniel: 1,000

6. LONG-TERM POWER SALES AGREEMENTS

The Company and the other operating affiliates have long-term contractual agreements for the sale of capacity to certain non-affiliated utilities located outside the system's service area. The unit power sales agreements are firm and pertain to capacity related to specific generating units. Because the energy is generally sold at cost under these agreements, profitability is primarily affected by revenues from capacity sales. The capacity revenues from these sales were $20.3 million in 2000, $19.8 million in 1999, and $22.5 million in 1998. Capacity revenues increased slightly in 2000 due to the recovery of higher operating expenses experienced during the year.

Unit power from specific generating plants of Southern Company is currently being sold to Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), and Jacksonville Electric Authority (JEA). Under these agreements, 209 megawatts of net dependable capacity were sold by the Company during 2000. Sales will increase slightly to 210 megawatts per year in 2001 and remain close to that level, unless reduced by FP&L, FPC, and JEA for the periods after 2001 with a minimum of three years notice, until the expiration of the contracts in 2010.

7. INCOME TAXES

At December 31, 2000, the tax-related regulatory assets to be recovered from customers were $16.0 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 2000, the tax-related regulatory liabilities to be credited to customers were $38.3 million. 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 federal and state income tax provisions are as follows:

	2000	1999	1998
	(in thousands)		
Total provision for income taxes:			
Federal--			
Current	**$37,250**	$33,973	$31,746
Deferred	**(11,159)**	(6,107)	(4,467)
	26,091	27,866	27,279
State--			
Current	**5,796**	5,267	5,137
Deferred	**(1,357)**	(502)	(217)
	4,439	4,765	4,920
Total	**$30,530**	$32,631	$32,199

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:

	2000	1999
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$172,646**	$168,662
Other	**14,262**	24,272
Total	**186,908**	192,934
Deferred tax assets:		
Federal effect of state deferred taxes	**8,703**	9,293
Postretirement benefits	**9,205**	8,456
Other	**14,742**	12,526
Total	**32,650**	30,275
Net deferred tax liabilities	**154,258**	162,659
Less current portion, net	**(816)**	(117)
Accumulated deferred income taxes in the Balance Sheets	**$155,074**	$162,776

Deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation and amortization in the Statements of Income. Credits amortized in this manner amounted to $1.9 million in 2000, 1999, and 1998. At December 31, 2000, 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:

	2000	1999	1998
Federal statutory rate	**35%**	35%	35%
State income tax, net of federal deduction	**4**	4	4
Non-deductible book depreciation	**1**	1	1
Difference in prior years' deferred and current tax rate	**(2)**	(2)	(2)
Other, net	**(1)**	-	(2)
Effective income tax rate	**37%**	38%	36%

The Company and the other subsidiaries of Southern Company file a consolidated federal tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis.

8. COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES

In January 1997, Gulf Power Capital Trust I (Trust I), of which the Company owns all of the common securities, issued $40 million of 7.625 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust I are $41 million aggregate principal amount of the Company's 7.625 percent junior subordinated notes due December 31, 2036.

In January 1998, Gulf Power Capital Trust II (Trust II), of which the Company owns all of the common securities, issued $45 million of 7.0 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust II are $46 million aggregate principal amount of the Company's 7.0 percent junior subordinated notes due December 31, 2037.

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 payment obligations with respect to the preferred securities of Trust I and Trust II. Trust I and Trust II are subsidiaries of the Company, and accordingly are consolidated in the Company's financial statements.

9. SECURITIES DUE WITHIN ONE YEAR

At December 31, 2000, the Company had an improvement fund requirement of $850,000. The first mortgage bond improvement fund requirement amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control revenue bond obligations. The requirement may be satisfied by depositing cash, reacquiring bonds, or by pledging additional property equal to 1 and 2/3 times the requirement.

10. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture contains various common stock dividend restrictions, which remain in effect as long as the bonds are outstanding. At December 31, 2000, retained earnings of $127 million were restricted against the payment of cash dividends on common stock under the terms of the mortgage indenture.

11. QUARTERLY FINANCIAL DATA (Unaudited)

Summarized quarterly financial data for 2000 and 1999 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2000	**$138,498**	**$16,007**	**$4,653**
June 2000	**182,120**	**30,505**	**12,927**
September 2000	**232,533**	**52,614**	**26,438**
December 2000	**161,168**	**20,755**	**7,825**
March 1999	$134,506	$15,665	$ 4,799
June 1999	166,815	29,253	13,226
September 1999	218,264	54,429	28,582
December 1999	154,514	19,815	7,060

The Company's business is influenced by seasonal weather conditions and the timing of rate changes, among other factors.

ELECTED FINANCIAL AND OPERATING DATA 1996-2000
ulf Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
perating Revenues (in thousands)	**$714,319**	$674,099	$650,518	$625,856	$634,365
et Income after Dividends on Preferred Stock (in thousands)	**$51,843**	$53,667	$56,521	$57,610	$57,845
ash Dividends on Common Stock (in thousands)	**$59,000**	$61,300	$57,200	$64,600	$58,300
eturn on Average Common Equity (percent)	**12.20**	12.63	13.20	13.33	13.27
otal Assets (in thousands)	**$1,315,496**	$1,308,495	$1,267,901	$1,265,612	$1,308,366
ross Property Additions (in thousands)	**$95,807**	$69,798	$69,731	$54,289	$61,386
apitalization (in thousands):					
ommon stock equity	**$427,378**	$422,313	$427,652	$428,718	$435,758
eferred stock	**4,236**	4,236	4,236	13,691	65,102
ompany obligated mandatorily redeemable preferred securities	**85,000**	85,000	85,000	40,000	-
ong-term debt	**365,993**	367,449	317,341	296,993	331,880
otal (excluding amounts due within one year)	**$882,607**	$878,998	$834,229	$779,402	$832,740
apitalization Ratios (percent):					
ommon stock equity	**48.4**	48.0	51.3	55.0	52.3
eferred stock	**0.5**	0.5	0.5	1.8	7.8
ompany obligated mandatorily redeemable preferred securities	**9.6**	9.7	10.2	5.1	-
ong-term debt	**41.5**	41.8	38.0	38.1	39.9
otal (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
ecurity Ratings:					
rst Mortgage Bonds -					
Moody's	**A1**	A1	A1	A1	A1
Standard and Poor's	**A+**	AA-	AA-	AA-	A+
Fitch	**AA-***	AA-	AA-	AA-	AA-
eferred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	A-	A	A	A
Fitch	**A***	A	A+	A+	A+
nsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	-
Standard and Poor's	**A**	A	A	A	-
Fitch	**A+***	A+	A+	A+	-
ustomers (year-end):					
esidential	**321,731**	315,240	307,077	300,257	291,196
ommercial	**47,666**	47,728	46,370	44,589	43,196
dustrial	**280**	267	257	267	278
ther	**442**	316	268	264	162
otal	**370,119**	363,551	353,972	345,377	334,832
mployees (year-end):	**1,327**	1,339	1,328	1,328	1,384

*Effective 1/22/01 the Fitch Security Ratings for First Mortgage Bonds, Preferred Stock, and Unsecured Long-Term Debt are A+, A-, and A respectively.

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)

Gulf Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands):					
Residential	**$ 308,728**	$277,311	$ 276,208	$ 277,609	$ 285,498
Commercial	**181,584**	165,871	160,960	164,435	164,181
Industrial	**76,539**	67,404	69,850	77,492	78,994
Other	**(4,689)**	2,174	2,100	2,083	2,056
Total retail	**562,162**	512,760	509,118	521,619	530,729
Sales for resale - non-affiliates	**66,890**	62,354	61,893	63,697	63,201
Sales for resale - affiliates	**66,995**	66,110	42,642	16,760	17,762
Total revenues from sales of electricity	**696,047**	641,224	613,653	602,076	611,692
Other revenues	**18,272**	32,875	36,865	23,780	22,673
Total	**$714,319**	$674,099	$650,518	$625,856	$634,365
Kilowatt-Hour Sales (in thousands):					
Residential	**4,790,038**	4,471,118	4,437,558	4,119,492	4,159,924
Commercial	**3,379,449**	3,222,532	3,111,933	2,897,887	2,808,634
Industrial	**1,924,749**	1,846,237	1,833,575	1,903,050	1,808,086
Other	**18,730**	19,296	18,952	18,101	17,815
Total retail	**10,112,966**	9,559,183	9,402,018	8,938,530	8,794,459
Sales for resale - non-affiliates	**1,705,486**	1,561,972	1,341,990	1,531,179	1,534,097
Sales for resale - affiliates	**1,916,526**	2,511,983	1,758,150	848,135	709,647
Total	**13,734,978**	13,633,138	12,502,158	11,317,844	11,038,203
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**6.45**	6.20	6.22	6.74	6.86
Commercial	**5.37**	5.15	5.17	5.67	5.85
Industrial	**3.98**	3.65	3.81	4.07	4.37
Total retail	**5.56**	5.36	5.41	5.84	6.03
Sales for resale	**3.70**	3.15	3.37	3.38	3.61
Total sales	**5.07**	4.70	4.91	5.32	5.54
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,992**	14,318	14,577	13,894	14,457
Residential Average Annual Revenue Per Customer	**$966.26**	$888.01	$907.35	$936.30	$992.17
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,188**	2,188	2,188	2,174	2,174
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,154**	2,085	2,040	1,844	2,136
Summer	**2,285**	2,161	2,146	2,032	1,961
Annual Load Factor (percent)	**55.4**	55.2	55.3	55.5	51.4
Plant Availability Fossil-Steam (percent):	**85.2**	87.2	87.6	91.0	91.8
Source of Energy Supply (percent):					
Coal	**87.8**	89.8	89.2	87.1	87.8
Oil and gas	**1.6**	2.5	2.0	0.4	0.5
Purchased power -					
From non-affiliates	**7.6**	5.9	5.5	3.5	2.7
From affiliates	**3.0**	1.8	3.3	9.0	9.0
Total	**100.0**	100.0	100.0	100.0	100.0

Officers

Travis J. Bowden
President and Chief Executive Officer
Age 62; 25 Years of Service

Francis M. Fisher, Jr.
Vice President - Power Delivery and Customer Operations
Age 52; 29 Years of Service

John E. Hodges, Jr.
Vice President - Marketing and Employee/External Affairs
Age 57; 34 Years of Service

Robert G. Moore
Vice President – Power Generation and Transmission
Age 51; 27 Years of Service

Arlan E. Scarbrough (1)
Vice President – Finance and Chief Financial Officer
Age 64; 38 Years of Service

Ronnie R. Labrato (2)
Comptroller and Chief Financial Officer
Age 47; 21 Years of Service

Warren E. Tate
Secretary and Treasurer
Age 58; 36 Years of Service

Susan D. Ritenour
Assistant Secretary and Assistant Treasurer
Age 41; 19 Years of Service

Linda G. Malone
Assistant Secretary and Assistant Treasurer
Age 51; 30 Years of Service

C. Alan Martin (3)
Vice President
Age 51; 27 Years of Service

Michael L. Scott
Vice President
Age 47; 24 Years of Service

Christopher C. Womack
Vice President
Age 42; 12 Years of Service

E. Wayne Boston
Assistant Secretary and Assistant Treasurer
Age 56; 30 Years of Service

Directors

Travis J. Bowden
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 1994

Fred C. Donovan, Sr.
Chairman and Chief Executive Officer
Baskerville-Donovan, Inc.
Pensacola, Florida. Elected 1991

H. Allen Franklin
President and Chief Operating Officer
Southern Company
Atlanta, Georgia. Elected 1999

W. Deck Hull, Jr.
President
Hull Company
Panama City, Florida. Elected 1983

Joseph K. Tannehill (4)
President and Chief Executive Officer
Tannehill International Industries
Lynn Haven, Florida. Elected 1985

Barbara H. Thames
Chief Operating Officer
West Florida Regional Medical Center
Pensacola, Florida. Elected 1997

(1) Retirement effective July 1, 2000.
(2) Appointed by CEO on July 1, 2000 and elected July 28, 2000.
(3) Resignation effective February 25, 2000.
(4) Leave of absence effective September 1, 2000 to December 1, 2001.

General
This annual report is submitted for general information. It 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 Florida. The Company sells electricity to some 370 thousand customers within its service area of approximately 7,400 square miles in the Florida panhandle. In 2000, retail energy sales accounted for 74 percent of the Company's total sales of 13.7 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.

Registrar, Transfer Agent, and Dividend Paying Agent
All series of Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

Trustee, Registrar, and Interest Paying Agent
All series of First Mortgage Bonds, Senior Notes, Junior Subordinated Notes, and Trust Preferred Securities
The Chase Manhattan Bank
Global Trust Services
15th Floor
450 West 33rd Street
New York, NY 10001-2697

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.

Corporate Office
Principal Address & Deliveries:
Gulf Power Company
500 Bayfront Parkway
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GULF POWER
A SOUTHERN COMPANY

www.gulfpower.com

Schedule F-2 | FINANCIAL STATEMENTS - OPINION OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS |

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 010949-EI	EXPLANATION: Provide the opinion of the Independent Certified Public Accountants and other sections of the consolidated financial statements not elsewhere filed for the most recent two years. If not otherwise available, certified financial statements need not be obtained solely to satisfy this MFR.	Type of Data Shown: _ Projected Test Year Ended 5/31/03 _ Prior Year Ended 5/31/02 X Historical Year 12/31/00 Witness: R. R. Labrato

Please refer to Schedule F-1 for 2000 opinion.

1999 Annual Report is attached for the 1999

opinion.

Supporting Schedules: | Recap Schedules:

ANNUAL REPORT 1999

GULF POWER

A SOUTHERN COMPANY

CONTENTS

Gulf Power Company 1999 Annual Report

SUMMARY

	1999	1998	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$674,099**	$650,518	3.6
Operating expenses	**$554,937**	$528,164	5.1
Net income after dividends on preferred stock	**$53,667**	$56,521	(5.0)
Gross property additions	**$69,798**	$69,731	0.1
Total assets	**$1,308,495**	$1,267,901	3.2
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**9,559,183**	9,402,018	1.7
Sales for resale - non-affiliates	**1,561,972**	1,341,990	16.4
Sales for resale - affiliates	**2,511,983**	1,758,150	42.9
Total	**13,633,138**	12,502,158	9.0
Customers served at year-end	**363,551**	353,972	2.7
Peak-hour demand, net *(in megawatts)*	**2,161**	2,146	0.7
Capitalization Ratios *(percent)*:			
Common stock equity	**48.0**	51.3	(6.4)
Preferred stock	**0.5**	0.5	0.0
Trust preferred securities	**9.7**	10.2	(4.9)
Long-term debt	**41.8**	38.0	10.0
Return on Average Common Equity *(percent)*	**12.63**	13.20	(4.3)

It is an exciting time, not only for Gulf Power Company, but for all of us in Northwest Florida. 1999 brought us the end of a century and the beginning of a new millenium.

We faced many challenges in 1999 with one of the main ones being the transition to the Year 2000. It was a lot of hard work, but the employees of Gulf Power and Southern Company successfully guided our companies through that transition.

During 1999, Gulf Power added 9,579 customers across its service area. Our continuing growth has led to several all-time highs for the company during the past year. First, we set an all-time high peak demand of 2,169 megawatts during the month of August, surpassing the previous record of 2,154 megawatts set in August of 1998.

Second, the company sold 13.6 billion kilowatt-hours in 1999, breaking our 1998 record total of 12.5 billion kilowatt-hours. The monthly rate for 1,000 kilowatt-hours for residential customers in December 1999 was $62.03. Gulf Power's residential customers continue to pay one of the lowest prices for electricity in the nation.

Also during 1999, Gulf Power's continuing commitment to provide low cost, highly reliable customer service allowed the company to achieve a new all-time high of 87 percent for the year in the public confidence survey of our customers. Gulf Power also finished first overall in the nation on a 1999 customer satisfaction survey of utilities throughout the country.

Finally, in October 1999, the Florida Public Service Commission approved an order reducing Gulf Power's retail base rates by $10 million annually and ordering a revenue sharing plan. The rate reduction became effective with meter readings on November 4, 1999.

As Gulf Power moves forward into a new century, our goal continues to be one of high reliability, low cost and superior customer satisfaction. Thank you for your continued support and confidence.

Sincerely,

Travis Bowden
President and Chief Executive Officer
March 24, 2000

The management of Gulf 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 generally accepted accounting principles appropriate in the circumstances 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 books and 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 audit committee of the board of directors, composed of directors who are not employees, provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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 Gulf Power Company in conformity with generally accepted accounting principles.

Travis J. Bowden
President
and Chief Executive Officer

Arlan E. Scarbrough
Chief Financial Officer

February 16, 2000

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Gulf Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (a Maine corporation and a wholly owned subsidiary of Southern Company) as of December 31, 1999 and 1998, 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, 1999. 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 13-28) referred to above present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 1999 and 1998, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 16, 2000

RESULTS OF OPERATIONS

Earnings

Gulf Power Company's 1999 net income after dividends on preferred stock was $53.7 million, a decrease of $2.8 million from the previous year. In 1998, earnings were $56.5 million, down $1.1 million when compared to 1997. The decrease in earnings in 1999, as well as 1998, was primarily a result of higher expenses than in the prior year.

Revenues

Operating revenues increased in 1999 and 1998 when compared to 1998 and 1997, respectively. The following table summarizes the factors impacting operating revenues for the past three years:

	Increase (Decrease) From Prior Year		
	1999	1998	1997
	(in thousands)		
Retail --			
Growth and price change	**$10,348**	$15,021	$ 4,005
Weather	**(7,879)**	6,656	(5,277)
Regulatory cost recovery and other	**1,173**	(34,179)	(7,837)
Total retail	**3,642**	(12,502)	(9,109)
Sales for resale--			
Non-affiliates	**461**	(1,804)	496
Affiliates	**23,468**	25,882	(1,002)
Total sales for resale	**23,929**	24,078	(506)
Other operating revenues	**(3,990)**	13,086	1,106
Total operating revenues	**$23,581**	$24,662	$(8,509)
Percent change	**3.6%**	3.9%	(1.3)%

Retail revenues of $512.8 million in 1999 increased $3.6 million, or 0.7 percent, from the prior year due primarily to an increase in the number of retail customers served by the Company. Retail revenues for 1998 decreased $12.5 million, or 2.4 percent, when compared to 1997 due primarily to the recovery of lower fuel costs. The price per ton of coal, which is the Company's primary fuel source, was lower in 1998 as the costs related to prior year coal contract renegotiations were fully amortized and a major coal contract price was reduced. See Note 5 to the financial statements under "Fuel Committments" for further information.

The 1999 increase in regulatory cost recovery and other retail revenues over 1998 is primarily attributable to the recovery of increased purchased power capacity costs. The 1998 decrease in regulatory cost recovery and other retail revenues over 1997 is primarily attributable to decreased fuel costs as mentioned previously. Regulatory cost recovery and other includes recovery provisions for fuel expense and the energy component of purchased power costs; energy conservation costs; purchased power capacity costs; and environmental compliance costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further information.

Sales for resale were $128.5 million in 1999, an increase of $24 million, or 23 percent, over 1998 primarily due to additional energy sales to affiliated companies, which is discussed below. Revenues from sales to utilities outside the service area under long-term contracts consist of capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components under these long-term contracts were as follows:

	1999	1998	1997
	(in thousands)		
Capacity	**$19,792**	$22,503	$24,899
Energy	**20,251**	14,556	18,160
Total	**$40,043**	$37,059	$43,059

Declining capacity revenues are due primarily to the decline in net plant investment related to these sales. In addition, the decline in 1999 reflects a reduction in the authorized rate of return on the equity component of the investment.

Sales to affiliated companies vary from year to year depending on demand and the availability and cost of generating resources at each company. These sales have little impact on earnings.

Other operating revenues decreased in 1999 and increased in 1998 due primarily to adjustments to reflect differences between recoverable costs and the amounts actually reflected in current rates. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further discussion.

Energy Sales

Kilowatt-hour sales for 1999 and the percent changes by year were as follows:

	KWH	Percent Change		
	1999	1999	1998	1997
	(millions)			
Residential	4,471	0.8%	7.7%	(1.0)%
Commercial	3,223	3.6	7.4	3.2
Industrial	1,846	0.7	(3.7)	5.3
Other	19	0.0	4.7	1.6
Total retail	9,559	1.7	5.2	1.6
Sales for resale				
Non-affiliates	1,562	16.4	(12.4)	(0.2)
Affiliates	2,512	42.9	107.3	19.5
Total	13,633	9.0	10.5	2.5

In 1999, total retail energy sales increased due to increases from 1998 in the number of residential, commercial and industrial customers. Total energy sales increased in 1998 when compared to 1997 due to higher temperatures when compared to the milder-than-normal temperatures in 1997 and due to increases in the number of residential and commercial customers. The decrease in industrial energy sales in 1998 when compared to 1997 primarily reflects the shut down of a major industrial customer's plant site and temporary production delays of other industrial customers. See "Future Earnings Potential" for information on the Company's initiatives to remain competitive and to meet conservation goals set by the Florida Public Service Commission (FPSC).

An increase in energy sales for resale to non-affiliates of 16.4 percent in 1999 when compared 1998 and a decrease of 12.4 percent in 1998 when compared to 1997 are primarily related to unit power sales under long-term contracts to other Florida utilities and bulk power sales under short-term contracts to other non-affiliated utilities. Energy sales to affiliated companies vary from year to year as mentioned previously.

Expenses

Total operating expenses in 1999 increased $26.8 million, or 5.1 percent, over the amount recorded in 1998 due primarily to higher fuel and purchased power expenses, offset by lower other operation expenses. In 1998, total operating expenses increased $26.5 million, or 5.3 percent, from 1997. The increase was due primarily to higher fuel, purchased power, and maintenance expenses offset by lower other operation expenses.

Fuel expenses in 1999, when compared to 1998, increased $11.5 million, or 5.9 percent. In 1998, fuel expenses increased $16.6 million, or 9.2 percent, when compared to 1997. The increases were the result of increased generation resulting from a higher demand for energy, while average fuel costs decreased as noted below.

Purchased power expenses increased in 1999 by $13.2 million, or 30.2 percent, over 1998 and purchased power expenses for 1998 increased over 1997 by $6.9 million, or 18.8 percent, due to a higher demand for energy in both years.

The amount and sources of generation and the average cost of fuel per net kilowatt-hour generated were as follows:

	1999	1998	1997
Total generation (millions of kilowatt-hours)	13,095	11,986	10,435
Sources of generation (percent)			
Coal	97.4	98.0	99.6
Oil and gas	2.6	2.0	0.4
Average cost of fuel per net kilowatt-hour generated (cents)--	1.60	1.69	1.99

Other operation expenses decreased $4.3 million, or 3.6 percent, in 1999 from the 1998 level and $7.3 million, or 5.7 percent, in 1998 from the 1997 level due to a decrease in the amortization costs of prior year payments related to renegotiations of coal supply contracts. The 1998 decrease was partially offset by higher implementation costs of a new customer accounting system, increased costs related to the Year 2000 program and an increase in the accrual to the accumulated provision for property damage.

Depreciation and amortization expense increased $5.5 million, or 9.2 percent, in 1999 when compared to 1998 due primarily to a reduction in the amortization of gains from the 1998 sale of emission allowances.

Maintenance expenses in 1998 increased by $9.3 million, or 19.4 percent, over 1997 due primarily to scheduled maintenance at Plant Crist and Plant Smith and increased transmission and distribution maintenance.

Interest on long-term debt in 1999 increased $1.7 million, or 8.4 percent, when compared to 1998 due primarily to two first mortgage bonds maturing in 1998 and being replaced by senior notes at a slightly higher interest rate, and the issuance of $50 million of senior notes in August 1999. In 1998, interest on long-term debt decreased $2.0 million, or 9.1 percent, from 1997 mostly due to a decrease in interest expense on pollution control bonds refinanced in 1997 and two long-term bank notes that matured in 1998. This decrease was partially offset by an increase in interest due to the replacement in 1998 of the two maturing first mortgage bonds with senior notes at a slightly higher interest rate.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of historical costs. Therefore, inflation creates an economic loss because the Company is recovering its cost 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.

Future Earnings Potential

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from energy sales growth to a potentially less regulated and more competitive environment.

Gulf Power currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in northwest Florida. Prices for electricity provided by the Company to retail customers are set by the FPSC.

Future earnings in the near term will depend upon growth in energy sales, which is subject to a number of factors. Traditionally, these factors have included weather, competition, changes in 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. In early 1999, the FPSC Staff and the Company became involved in serious discussions primarily related to reducing the Company's authorized rate of return. On October 1, 1999 the Office of Public Counsel, the Coalition for Equitable Rates, the Florida Industrial Power Users Group, and the Company jointly filed a petition to resolve the issues. The stipulation included a reduction to retail base rates of $10 million annually and provides for revenues to be shared within set ranges for 1999 through 2002. Customers would receive two-thirds of any revenue within the ranges and the Company would retain one-third. For calendar year 2000, the Company's retail base rate revenues in excess of $352 million up to $368 million will be shared between the Company and its retail customers on the one-third/two-thirds basis. Retail base rate revenues above $368 million for calendar year 2000 will be refunded to the Company's customers. These set ranges increase gradually until the expiration of the plan. The Sharing Plan will be in place until the earlier of the in-service date of Smith Unit 3 or December 31, 2002. The parties could not agree on the appropriate Return on Equity (ROE). Consequently, the Company filed a request to prospectively reduce its authorized ROE range from 11 to 13 percent to 10.5 to 12.5 percent in order to help ensure that the FPSC would approve the stipulation. Both the stipulation and the ROE request were approved by the Commission on October 5, 1999, with an effective date of November 4, 1999.

The electric utility industry in the United States is currently undergoing a period of dramatic change 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 Company is positioning the business to meet the challenge of this major change in the traditional practice of selling electricity. The Energy Act allows independent power producers (IPPs) to access the Company's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build cogeneration plants for industrial and commercial customers and sell energy generation to other utilities. The Company has and will continue to evaluate opportunities to partner and participate in profitable cogeneration projects. In 1998, partnering with one of the Company's largest industrial customers, construction was completed on 15 megawatts of Company-owned cogeneration on the customer's plant site. Also, electricity sales for resale rates are being driven down by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers. The Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers to choose their electricity provider. As these initiatives materialize, the structure of the utility industry continues to change. 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 or are being discussed in Florida, none have been enacted to date. Enactment would require numerous issues to be resolved, including significant ones relating to transmission pricing and recovery of any stranded investments. The inability of the Company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on financial condition and results of operation. The Company is attempting to minimize or reduce its cost exposure.

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

In 1996, the FPSC approved a new optional Commercial/Industrial Service Rider (CISR), which is applicable to the rate schedules for the Company's largest existing and potential customers who are able to show they have viable alternatives to purchasing the Company's energy services. The CISR, approved as a pilot program, provides the flexibility needed to enable the Company to offer its services in a more competitive manner to these customers. The publicity of the CISR ruling, increased competitive pressures, and general awareness of customer choice pilots and proposals across the country have stimulated interest on the part of customers in custom tailored offerings. The Company has participated in one-on-one discussions with many of these customers, and has negotiated and executed two Contract Service Agreements within the CISR pilot program. The pilot program ends in September of 2000 and the company is currently reviewing its options.

Every five years the FPSC establishes numeric demand side management goals. The Company proposed numeric goals for the ten-year period from 2000 to 2009. The proposed goals consisted of the total, cost-effective winter and summer peak demand (kilowatts) and annual energy (kilowatt-hour) savings reasonably achievable from demand side management for the residential and commercial/industrial classes. The Company submitted its 2000 Demand Side Management Plan to the FPSC on December 29, 1999. The plan describes the Company's proposed programs it will employ to reach the numeric goals. The plan relies heavily on innovative pricing and energy efficient construction. The FPSC is expected to issue its final order on the Company's 2000 Demand Side Management Plan in mid-April 2000.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encourages utilities owning transmission systems to form RTOs on a voluntary basis. To facilitate the development of RTOs, the FERC will convene regional conferences for utilities, customers, and other members of the public to discuss the formation of RTOs. In addition to participating in the regional conferences, utilities owning transmission systems, including Southern Company, are required to make a filing by October 15, 2000. The filing must contain either a proposal for RTO participation or a description of the efforts made to participate in an RTO, the reasons for non-participation, any obstacles to participation, and any plans for further work toward participation. The RTOs that are proposed in the filings should be operational by December 15, 2001. Southern Company is evaluating this issue and formulating its response. The outcome of this matter cannot now be determined.

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." Also, Florida legislation adopted in 1993 that provides for recovery of prudent environmental compliance costs is discussed in Note 3 to the financial statements under "Environmental Cost Recovery."

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. In the event that a portion of the Company's operations 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.

Exposure to Market Risks

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates 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. Realized gains and losses are recognized in the income statements as incurred. At December 31, 1999, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. Also, based on the Company's overall interest rate exposure at December 31, 1999, a near-term 100 basis point change in interest rates would not materially affect the Company's financial statements.

New Accounting Standards

The FASB has issued Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, which must be adopted by January 1, 2001. This statement establishes accounting and reporting standards for derivative instruments – including certain derivative instruments embedded in other contracts – and for hedging activities. Adoption of this statement is not expected to have a material impact on the Company's financial statements.

Year 2000 Challenge

The work undertaken by the Company to ensure that all critical computer systems and other date sensitive devices would function correctly in the Year 2000 was successful. There were no material incidents reported and no disruption of electric service within the service area of the Company. There were no reports of significant events regarding third parties that impacted revenues or expenses.

The Company's original projected total costs for Year 2000 readiness were approximately $5 million. Final projected costs were also $5 million with no material costs remaining to be spent in 2000. From its inception through December 31, 1999, the Year 2000 program costs, recognized primarily as expense, amounted to $5 million, of which $2 million was recorded in 1999.

FINANCIAL CONDITION

Overview

The Company's financial condition continues to be very solid. During 1999, gross property additions were $69.8 million. Funds for the property additions were provided by operating activities. See the Statements of Cash Flows for further details.

Financing Activities

In 1999, the Company sold $50 million of senior notes and long-term bank notes totaling $27 million were retired. The remaining proceeds from this issuance were used to reduce short-term borrowing requirements. See the Statements of Cash Flows for further details.

Composite financing rates for the years 1997 through 1999 as of year end were as follows:

	1999	1998	1997
Composite interest rate on long-term debt	**6.0%**	6.1%	5.9%
Composite rate on trust preferred securities	**7.3%**	7.3%	7.6%
Composite preferred stock dividend rate	**5.1%**	5.1%	6.1%

The composite interest rate on long-term debt decreased in 1999 primarily due to lower interest rates on variable rate pollution control bonds.

Capital Requirements for Construction

The Company's gross property additions, including those amounts related to environmental compliance, are budgeted at $428 million for the three years beginning in 2000 ($106 million in 2000, $232 million in 2001, and $90 million in 2002). These amounts include $198.8 million for the years 2000 through 2002 for the estimated cost of a 574 megawatt combined cycle gas unit to be located in the eastern portion of its service area. The unit is expected to have an in-service date of June 2002. The remaining property additions budget is primarily for maintaining and upgrading transmission and distribution facilities and generating plants. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental 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

The Company will continue to retire higher-cost debt and preferred securities and replace these securities with lower-cost capital as market conditions and terms of the instruments permit.

Environmental Matters

In November 1990, the Clean Air Act was signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected the Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants are required in two phases. Phase I compliance began in 1995 and initially affected 28 generating units of Southern Company. As a result of Southern Company's compliance strategy, an additional 22 generating units were brought into compliance with Phase I requirements. Phase II compliance is required in 2000, and all fossil-fired generating plants will be affected.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I compliance totaled approximately $300 million for Southern Company, including approximately $42 million for Gulf Power.

For Phase II sulfur dioxide compliance, Southern Company currently uses emission allowances and increased fuel switching. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as required to meet Phase II limits and ozone non-attainment requirements. Compliance for Phase II and initial ozone non-attainment requirements increased total estimated construction expenditures by approximately $105 million. Phase II compliance is not expected to have a material impact on Gulf Power.

Following adoption of legislation in April of 1992 allowing electric utilities in Florida to seek FPSC approval of their Clean Air Act Compliance Plans, Gulf Power filed its petition for approval. The FPSC approved the Company's plan for Phase I compliance, deferring until a later date approval of its Phase II Plan.

In 1993, the Florida Legislature adopted legislation that allows a utility to petition the FPSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the Environmental Cost Recovery Clause.

In July 1997, the Environmental Protection Agency (EPA) revised the national ambient air quality standards for ozone and particulate matter. This revision makes the standards significantly more stringent. In September 1998, the EPA issued the final regional nitrogen oxide reduction rule to the states for implementation. The final rule affects 22 states, including Alabama and Georgia. See Note 6 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. The EPA's July 1997 standards and the September 1998 rule are being challenged in the courts by several states and industry groups. Implementation of the final state rules for these three initiatives could require substantial further reductions in nitrogen oxide and sulfur dioxide emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules.

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including: nitrogen oxide emission control strategies for ozone non-attainment areas; additional controls for hazardous air pollutant emissions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

On November 3, 1999, the EPA brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 6 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. Southern Company believes that its integrated utilities 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 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.

Gulf Power must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. 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 costs and has recognized in the financial statements costs to clean up known sites. For additional information, see Note 3 to the financial statements under "Environmental Cost Recovery."

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electric and magnetic fields, and other environmental health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electric and magnetic fields.

Sources of Capital

At December 31, 1999, the Company had approximately $15.8 million of cash and cash equivalents and $41.5 million of unused committed lines of credit with banks to meet its short-term cash needs. Refer to the Statements of Cash Flows for details related to the Company's financing activities. See Note 5 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company historically has relied on issuances of first mortgage bonds and preferred stock, in addition to pollution control revenue bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. Recently, the Company's financings have consisted of unsecured debt and trust preferred securities. In this regard, the Company sought and obtained stockholder approval in 1997 to amend its corporate charter eliminating restrictions on the amounts of unsecured indebtedness it may incur.

If the Company chooses to issue first mortgage bonds or preferred stock, it is required to meet certain coverage requirements specified in its mortgage indenture and corporate charter. The Company's ability to satisfy all coverage requirements is such that it could issue new first mortgage bonds and preferred stock to provide sufficient funds for all anticipated requirements.

Cautionary Statement Regarding Forward-Looking Information

The Company's 1999 Annual Report contains forward-looking and historical information. The Company cautions that there are various important factors that could cause actual results to differ materially from those indicated in the forward-looking information. Accordingly, there can be no assurance that such indicated results will be realized. These factors include legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry; the extent and timing of the entry of additional competition in the Company's markets; potential business strategies -- including acquisitions or dispositions of assets or internal restructuring -- that may be pursued by the company; state and federal rate regulation; changes in or application of environmental and other laws and regulations to which the company is subject; political, legal and economic conditions and developments; financial market conditions and the results of financing efforts; changes in commodity prices and interest rates; weather and other natural phenomena; and other factors discussed in the reports -- including 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, 1999, 1998, and 1997
Gulf Power Company 1999 Annual Report

	1999	1998	1997
		(in thousands)	
Operating Revenues:			
Retail sales	**$512,760**	$509,118	$521,619
Sales for resale --			
Non-affiliates	**62,354**	61,893	63,697
Affiliates	**66,110**	42,642	16,760
Other revenues	**32,875**	36,865	23,780
Total operating revenues	**674,099**	650,518	625,856
Operating Expenses:			
Operation --			
Fuel	**209,031**	197,462	180,843
Purchased power --			
Non-affiliates	**46,332**	29,369	11,938
Affiliates	**10,703**	14,445	24,955
Other	**114,670**	119,011	126,266
Maintenance	**57,830**	57,286	47,988
Depreciation and amortization	**64,589**	59,129	57,874
Taxes other than income taxes	**51,782**	51,462	51,775
Total operating expenses	**554,937**	528,164	501,639
Operating Income	**119,162**	122,354	124,217
Other Income (Expense):			
Interest income	**1,771**	931	1,203
Other, net	**(1,357)**	(2,339)	(992)
Earnings Before Interest and Income Taxes	**119,576**	120,946	124,428
Interest Charges and Other:			
Interest on long-term debt	**21,375**	19,718	21,699
Interest on notes payable	**2,371**	1,190	891
Amortization of debt discount, premium and expense, net	**1,989**	2,100	2,281
Other interest charges	**1,126**	2,548	2,076
Distributions on preferred securities of subsidiary	**6,200**	6,034	2,804
Total interest charges and other, net	**33,061**	31,590	29,751
Earnings Before Income Taxes	**86,515**	89,356	94,677
Income taxes (Note 8)	**32,631**	32,199	33,450
Net Income	**53,884**	57,157	61,227
Dividends on Preferred Stock	**217**	636	3,617
Net Income After Dividends on Preferred Stock	**$ 53,667**	$ 56,521	$ 57,610

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 1999 and 1998
Gulf Power Company 1999 Annual Report

Assets	1999	1998
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 15,753**	$ 969
Receivables --		
Customer accounts receivable	**55,108**	49,067
Other accounts and notes receivable	**4,325**	3,514
Affiliated companies	**7,104**	3,442
Accumulated provision for uncollectible accounts	**(1,026)**	(996)
Fossil fuel stock, at average cost	**29,869**	24,213
Materials and supplies, at average cost (Note 1)	**30,088**	28,025
Regulatory clauses under recovery (Note 1)	**11,611**	9,737
Other	**5,354**	9,725
Total current assets	**158,186**	127,696
Property, Plant, and Equipment:		
In service (Notes 1 and 6)	**1,853,664**	1,809,901
Less accumulated provision for depreciation	**821,970**	784,111
	1,031,694	1,025,790
Construction work in progress	**34,164**	34,863
Total property, plant, and equipment	**1,065,858**	1,060,653
Other Property and Investments	**1,481**	588
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 8)	**25,264**	25,308
Prepaid pension costs (Note 2)	**17,734**	13,770
Debt expense, being amortized	**2,526**	2,565
Premium on reacquired debt, being amortized	**17,360**	18,883
Other	**20,086**	18,438
Total deferred charges and other assets	**82,970**	78,964
Total Assets	**$1,308,495**	$1,267,901

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 1999 and 1998
Gulf Power Company 1999 Annual Report

Liabilities and Stockholder's Equity	**1999**	1998
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 10)	**$ -**	$ 27,000
Notes payable	**55,000**	31,500
Accounts payable --		
Affiliated	**14,878**	19,756
Other	**22,581**	23,697
Customer deposits	**12,778**	12,560
Taxes accrued --		
Income taxes	**4,889**	-
Other	**7,707**	7,432
Interest accrued	**9,255**	5,184
Vacation pay accrued	**4,199**	4,035
Other	**4,961**	10,051
Total current liabilities	**136,248**	141,215
Long-term debt (See accompanying statements)	**367,449**	317,341
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 8)	**162,776**	166,118
Deferred credits related to income taxes (Note 8)	**49,693**	52,465
Accumulated deferred investment tax credits	**27,712**	29,632
Employee benefits provisions	**31,735**	28,594
Other	**21,333**	15,648
Total deferred credits and other liabilities	**293,249**	292,457
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	**85,000**	85,000
Preferred stock (See accompanying statements)	**4,236**	4,236
Common stockholder's equity (See accompanying statements)	**422,313**	427,652
Total Liabilities and Stockholder's Equity	**$1,308,495**	$1,267,901

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 1999 and 1998
Gulf Power Company 1999 Annual Report

		1999	1998	1999	1998
		(in thousands)		*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
July 1, 2003	6.125%	**$ 30,000**	$ 30,000		
November 1, 2006	6.50%	**25,000**	25,000		
January 1, 2026	6.875%	**30,000**	30,000		
Total first mortgage bonds		**85,000**	85,000		
Long-term notes payable --					
7.05% due August 15, 2004		**50,000**	-		
7.50% due June 30, 2037		**20,000**	20,000		
6.70% due June 30, 2038		**49,926**	50,000		
Adjustable rate (5.72% at 1/1/99) due November 20, 1999		**-**	27,000		
Total long-term notes payable		**119,926**	97,000		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized with first mortgage bonds:					
5.25% to 6.30% due 2006-2026		**108,700**	108,700		
Variable rate (3.70% at 1/1/00) due 2024		**20,000**	20,000		
Collateralized with other property:					
Variable rate (3.75% at 1/1/00) due 2022		**40,930**	40,930		
Total other long-term debt		**169,630**	169,630		
Unamortized debt premium (discount), net		**(7,107)**	(7,289)		
Total long-term debt (annual interest requirement -- $22.5 million)		**367,449**	344,341		
Less amount due within one year (Note 10)		**-**	27,000		
Long-term debt excluding amount due within one year		**367,449**	317,341	**41.8%**	38.0%
Company Obligated Mandatorily Redeemable Preferred Securities: (Note 9)					
$25 liquidation value --					
7.00%		**45,000**	45,000		
7.625%		**40,000**	40,000		
Total (annual distribution requirement -- $6.2 million)		**85,000**	85,000	**9.7**	10.2
Cumulative Preferred Stock:					
$100 par value					
4.64% to 5.44%		**4,236**	4,236		
Total (annual dividend requirement -- $0.2 million)		**4,236**	4,236		
Less amount due within one year		**-**	-		
Total excluding amount due within one year		**4,236**	4,236	**0.5**	0.5
Common Stockholder's Equity:					
Common stock, without par value --					
Authorized and Outstanding - 992,717 shares in 1999 and 1998		**38,060**	38,060		
Paid-in capital		**221,254**	218,960		
Premium on preferred stock		**12**	12		
Retained earnings (Note 11)		**162,987**	170,620		
Total common stockholder's equity		**422,313**	427,652	**48.0**	51.3
Total Capitalization		**$878,998**	$834,229	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 1999, 1998, and 1997
Gulf Power Company 1999 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1997	$38,060	$218,437	$81	$179,180	$435,758
Net income after dividends on preferred stock	-	-	-	57,610	57,610
Cash dividends on common stock	-	-	-	(64,600)	(64,600)
Other	-	1	(69)	18	(50)
Balance at December 31, 1997	38,060	218,438	12	172,208	428,718
Net income after dividends on preferred stock	-	-	-	56,521	56,521
Capital contributions from parent company	-	522	-	-	522
Cash dividends on common stock	-	-	-	(57,200)	(57,200)
Other	-	-	-	(909)	(909)
Balance at December 31, 1998	38,060	218,960	12	170,620	427,652
Net income after dividends on preferred stock	-	-	-	**53,667**	**53,667**
Capital contributions from parent company	-	**2,294**	-	-	**2,294**
Cash dividends on common stock	-	-	-	**(61,300)**	**(61,300)**
Balance at December 31, 1999	**$38,060**	**$221,254**	**$12**	**$162,987**	**$422,313**

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 1999, 1998, and 1997

Gulf Power Company 1999 Annual Report

	1999	1998	1997
		(in thousands)	
Operating Activities:			
Net income	**$ 53,884**	$ 57,157	$ 61,227
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**68,721**	69,633	72,860
Deferred income taxes and investment tax credits, net	**(6,609)**	(4,684)	(7,047)
Other, net	**3,735**	3,463	4,831
Changes in certain current assets and liabilities --			
Receivables, net	**(10,484)**	11,308	(692)
Fossil fuel stock	**(5,656)**	(4,917)	9,056
Materials and supplies	**(2,063)**	609	1,618
Accounts payable	**(2,023)**	823	1,398
Other	**7,030**	(18,471)	22,296
Net cash provided from operating activities	**106,535**	114,921	165,547
Investing Activities:			
Gross property additions	**(69,798)**	(69,731)	(54,289)
Other	**(8,856)**	5,990	509
Net cash used for investing activities	**(78,654)**	(63,741)	(53,780)
Financing Activities:			
Increase (decrease) in notes payable, net	**23,500**	(15,500)	22,000
Proceeds --			
Other long-term debt	**50,000**	50,000	60,930
Preferred securities	**-**	45,000	40,000
Capital contributions from parent company	**2,294**	522	-
Retirements --			
First mortgage bonds	**-**	(45,000)	(25,000)
Other long-term debt	**(27,074)**	(8,326)	(56,902)
Preferred stock	**-**	(9,455)	(75,911)
Payment of preferred stock dividends	**(271)**	(792)	(5,370)
Payment of common stock dividends	**(61,300)**	(67,200)	(64,600)
Other	**(246)**	(4,167)	(3,014)
Net cash used for financing activities	**(13,097)**	(54,918)	(107,867)
Net Change in Cash and Cash Equivalents	**14,784**	(3,738)	3,900
Cash and Cash Equivalents at Beginning of Period	**969**	4,707	807
Cash and Cash Equivalents at End of Period	**$ 15,753**	$ 969	$ 4,707
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$27,670**	$28,044	$26,558
Income taxes (net of refunds)	**29,462**	38,782	36,010

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, a system service company, Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Southern Energy, Inc. (Southern Energy), Southern Nuclear Operating Company (Southern Nuclear), and other direct and indirect subsidiaries. The integrated Southeast utilities -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four states. Gulf Power Company provides electric service to the northwest panhandle of Florida. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). The system service company provides, at cost, specialized services to Southern Company and 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 Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Southern Energy acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Southern Energy businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

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 Florida Public Service Commission (FPSC). The Company follows generally accepted accounting principles and complies with the accounting policies and practices prescribed by the FPSC and the FERC. The preparation of financial statements in conformity with generally accepted accounting principles 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.

Related-Party Transactions

The Company has an agreement with Southern Company Services, Inc. (a wholly owned subsidiary of Southern Company) under which the following services are rendered to the company at cost: general and design engineering, purchasing, accounting and statistical, finance and treasury, tax, information resources, marketing, auditing, insurance and pension, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $43 million, $40 million, and $36 million during 1999, 1998, and 1997, respectively.

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 to the Company 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:

	1999	1998
	(in thousands)	
Deferred income tax debits	**$25,264**	$25,308
Deferred loss on reacquired debt	**17,360**	18,883
Environmental remediation	**5,745**	7,076
Vacation pay	**4,199**	4,035
Regulatory clauses under (over) recovery, net	**8,486**	3,700
Accumulated provision for property damage	**(5,528)**	(1,605)
Deferred income tax credits	**(49,693)**	(52,465)
Other, net	**(1,255)**	(480)
Total	**$ 4,578**	$ 4,452

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 any impairment to other assets, including plant, and write down the assets, if impaired, to their fair value.

Revenues and Regulatory Cost Recovery Clauses

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its service area located in northwest Florida and to wholesale customers in the Southeast.

The Company accrues revenues for service rendered but unbilled at the end of each fiscal period. The Company has a diversified base of customers and no single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged significantly less than 1 percent of revenues.

Fuel costs are expensed as the fuel is used. The Company's retail electric rates include provisions to periodically adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company also has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted monthly for differences between recoverable costs and amounts actually reflected in current rates.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.8 percent in 1999 and 1998 and 3.6 percent in 1997. The increase in 1998 is attributable to new depreciation rates, which were approved by the FPSC in 1998. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost -- together with the cost of removal, less salvage -- is charged to the accumulated provision for depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Also, the provision for depreciation expense includes an amount for the expected cost of removal of facilities.

Income Taxes

The Company uses the liability method of accounting for 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. The Company is included in the consolidated federal income tax return of Southern Company.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. 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 maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property (exclusive of minor items of property) is charged to utility plant.

Cash and Cash Equivalents

Temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Financial Instruments

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

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
At December 31, 1999	**$367,449**	**$349,791**
At December 31, 1998	$344,341	$357,100
Capital trust preferred securities:		
At December 31, 1999	**$85,000**	**$69,092**
At December 31, 1998	$85,000	$89,400

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

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.

Provision for Injuries and Damages

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by regulatory authorities, the Company provides for the uninsured costs of injuries and damages by charges to income amounting to $1.2 million annually. The expense of settling claims is charged to the provision to the extent available. The accumulated provision of $1.8 million and $1.3 million at December 31, 1999 and 1998, respectively, is included in other current liabilities in the accompanying Balance Sheets.

Provision for Property Damage

The Company provides for the cost of repairing damages from major storms and other uninsured property damages. This includes the full cost of storm and other damages to its transmission and distribution lines and the cost of uninsured damages to its generation and other property. The expense of such damages is charged to the provision account. At December 31, 1999 and 1998, the accumulated provision for property damage was $5.5 million and $1.6 million, respectively. In 1995, the FPSC approved the Company's request to increase the amount of its annual accrual to the accumulated provision for property damage account from $1.2 million to $3.5 million and approved a target level for the accumulated provision account between $25.1 and $36.0 million. The FPSC has also given the Company the flexibility to increase its annual accrual amount above $3.5 million, when the Company believes it is in a position to do so. The Company accrued $5.5 million in 1999 and $6.5 million in 1998 to the accumulated provision for property damage. The Company charged $1.6 million to the provision account in 1999. Charges to the provision account during 1998 totaled $4.2 million, which included $3.4 million related to Hurricane Georges.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, non-contributory pension plan that covers substantially all regular employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits when they retire. Trusts are funded to the extent required by the Company's regulatory commissions. The measurement date for plan assets and obligations is September 30 for each year.

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	
	1999	1998
	(in thousands)	
Balance at beginning of year	**$143,012**	$130,794
Service cost	**4,490**	4,107
Interest cost	**9,440**	9,572
Benefits paid	**(6,862)**	(6,663)
Actuarial loss (gain) and employee transfers	**(8,113)**	5,202
Balance at end of year	**$141,967**	$143,012

	Plan Assets 1999	1998
	(in thousands)	
Balance at beginning of year	**$212,934**	$222,196
Actual return on plan assets	**35,971**	1,310
Benefits paid	**(6,862)**	(6,663)
Employee transfers	**(558)**	(3,909)
Balance at end of year	**$241,485**	$212,934

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

	1999	1998
	(in thousands)	
Funded status	**$99,518**	$ 69,922
Unrecognized transition obligation	**(4,323)**	(5,043)
Unrecognized prior service cost	**4,495**	4,869
Unrecognized net gain	**(81,956)**	(55,978)
Prepaid asset recognized in the Balance Sheets	**$17,734**	$13,770

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

	1999	1998	1997
Service cost	**$4,490**	$ 4,107	$ 3,897
Interest cost	**9,440**	9,572	9,301
Expected return on plan assets	**(15,968)**	(14,827)	(13,675)
Recognized net gain	**(1,579)**	(1,891)	(1,656)
Net amortization	**(347)**	(347)	(347)
Net pension income	**$(3,964)**	$(3,386)	$ (2,480)

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 1999	1998
	(in thousands)	
Balance at beginning of year	**$49,303**	$39,669
Service cost	**1,087**	946
Interest cost	**3,261**	3,123
Benefits paid	**(1,177)**	(1,068)
Actuarial (loss) gain and employee transfers	**(4,464)**	3,614
Amendments	**-**	3,019
Balance at end of year	**$48,010**	$49,303

	Plan Assets 1999	1998
	(in thousands)	
Balance at beginning of year	**$9,603**	$9,455
Actual return on plan assets	**1,525**	54
Employer contributions	**1,245**	1,162
Benefits paid	**(1,177)**	(1,068)
Balance at end of year	**$11,196**	$9,603

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

	1999	1998
	(in thousands)	
Funded status	**$ (36,814)**	$(39,700)
Unrecognized transition obligation	**4,723**	5,079
Unrecognized prior service cost	**2,741**	2,900
Unrecognized net loss	**2,620**	8,187
Fourth quarter contributions	**300**	-
Accrued liability recognized in the Balance Sheets	**$(26,430)**	$(23,534)

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

	1999	1998	1997
Service cost	**$ 1,087**	$ 946	$ 896
Interest cost	**3,261**	3,123	2,845
Expected return on plan assets	**(794)**	(717)	(641)
Transition obligation	**356**	356	356
Prior service cost	**159**	119	-
Recognized net loss	**264**	128	184
Net postretirement cost	**$ 4,333**	$3,955	$3,640

The weighted average rates assumed in the actuarial calculations for both the pension plan and postretirement benefits were:

	1999	1998
Discount	**7.50%**	6.75%
Annual salary increase	**5.00%**	4.25%
Long-term return on plan assets	**8.50%**	8.50%

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.74 percent for 1999, decreasing gradually to 5.5 percent through the year 2005, 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, 1999 as follows (in thousands):

	1 Percent Increase	1 Percent Decrease
Benefit obligation	$3,627	$(3,086)
Service and interest costs	$320	$(269)

Work Force Reduction Programs

The Company recorded costs related to work force reduction programs of $0.2 million in 1999, $2.8 million in 1998, and $1.4 million in 1997. The Company has also incurred its pro rata share for the costs of affiliated companies' programs. The costs related to these programs were $0.6 million for 1999, $0.2 million for 1998, and $1.3 million for 1997. The Company has expensed all costs related to these work force reduction programs.

3. CONTINGENCIES AND REGULATORY MATTERS

Environmental Cost Recovery

In April 1993, the Florida Legislature adopted legislation for an Environmental Cost Recovery Clause (ECRC), which allows a utility to petition the FPSC for recovery of all prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital.

In January 1994, the FPSC approved the Company's initial petition under the ECRC for recovery of environmental costs. Initially, recovery under the ECRC was determined semi-annually. The FPSC approved annual recovery periods beginning with the October 1996 through September 1997 period. As of January 1999, the annual recovery period is on a calendar-year basis as approved by the FPSC in May 1998. Recovery includes a true-up of the prior period and a projection of the ensuing period. During 1999 and 1998, the Company recorded ECRC revenues of $11.6 million and $8.0 million, respectively.

At December 31, 1999, the Company's liability for the estimated costs of environmental remediation projects for known sites was $5.7 million. These estimated costs are expected to be expended from 2000 through 2006. These projects have been approved by the FPSC for recovery through the ECRC discussed above. Therefore, the Company recorded $1.2 million in current assets and current liabilities and $4.5 million in deferred assets and deferred liabilities representing the future recoverability of these costs.

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 6 under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. Southern Company believes that its integrated utilities 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.

4. CONSTRUCTION PROGRAM

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $106 million in 2000, $232 million in 2001, and $90 million in 2002. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; revised load growth estimates; changes in environmental regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 1999, significant purchase commitments were outstanding in connection with the construction program. The Company has budgeted $198.8 million for the years 2000 through 2002 for the estimated cost of a 574 megawatt combined cycle gas unit to be located in the eastern portion of its service area. The unit is expected to have an in-service date of June 2002. The Company will continue its construction program related to transmission and distribution facilities and the upgrading and extension of the useful lives of generating plants.

See Management's Discussion and Analysis under "Environmental Matters" for information on the impact of the Clean Air Act Amendments of 1990 and other environmental matters.

5. FINANCING AND COMMITMENTS

General

Current projections indicate that funds required for construction and other purposes, including compliance with environmental regulations, will be derived from operations; the sale of additional long-term unsecured debt, pollution control bonds, and preferred securities; bank notes; and capital contributions from Southern Company. In addition, the Company may issue additional long-term debt and preferred securities primarily for debt maturities and redemptions of higher-cost securities.

Bank Credit Arrangements

At December 31, 1999, the Company had $41.5 million of lines of credit with banks subject to renewal June 1 of each year, all of which remained unused. In addition, the Company has two unused committed lines of credit totaling $61.9 million that were established for liquidity support of its variable rate pollution control bonds. In connection with these credit lines, the Company has agreed to pay commitment fees and/or to maintain compensating balances with the banks. The compensating balances, which represent substantially all of the cash of the Company except for daily working funds and like items, are not legally restricted from withdrawal. In addition, the Company has bid-loan facilities with seven major money center banks that total $130 million, of which $50 million was committed at December 31, 1999.

Assets Subject to Lien

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

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into long-term commitments for the procurement of 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, 1999 were as follows:

Year	Fuel
	(in millions)
2000	$89
2001	70
2002	86
2003	90
2004	91
2005 - 2026	508
Total commitments	$934

In 1988, the Company made an advance payment of $60 million to a coal supplier under an arrangement to lower the cost of future coal purchased under an existing contract. This payment was fully amortized to expense on a per ton basis as of March 1998.

In December 1995, the Company made another payment of $22 million to the same coal supplier under an arrangement to lower the cost of future coal and/or to suspend the purchase of coal under an existing contract for 25 months. This payment was fully amortized to expense on a per ton basis as of March 1998.

The amortization expense of these contract renegotiations was recovered through the fuel cost recovery clause discussed under "Revenues and Regulatory Cost Recovery Clauses" in Note 1.

Lease Agreements

In 1989, the Company and Mississippi Power jointly entered into a twenty-two year operating lease agreement for the use of 495 aluminum railcars. In 1994, a second lease agreement for the use of 250 additional aluminum railcars was entered into for twenty-two years. Both of these leases are for the transportation of coal to Plant Daniel. At the end of each lease term, the Company has the option to renew the lease. In 1997, three additional lease agreements for 120 cars each were entered into for three years, with a monthly renewal option for up to an additional nine months.

The Company, as a joint owner of Plant Daniel, is responsible for one half of the lease costs. The lease costs are charged to fuel inventory and are allocated to fuel expense as the fuel is used. The Company's share of the lease costs charged to fuel inventories was $2.8 million in 1999 and $2.8 million in 1998. The annual amounts for 2000 through 2004 are expected to be $2.1 million, $1.7 million, $1.7 million, $1.7 million, and $1.8 million, respectively, and after 2004 are expected to total $14.4 million.

6. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel, a steam-electric generating plant located in Jackson County, Mississippi. In accordance with an operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of the plant.

The Company and Georgia Power jointly own Plant Scherer Unit No. 3. Plant Scherer is a steam-electric generating plant located near Forsyth, Georgia. In accordance with an operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's pro rata share of expenses related to both plants is included in the corresponding operating expense accounts in the Statements of Income.

At December 31, 1999, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit No. 3 (coal-fired)	Plant Daniel (coal-fired)
	(in thousands)	
Plant In Service	**$185,714(1)**	**$231,041**
Accumulated Depreciation	**$66,193**	**$113,687**
Construction Work in Progress	**$276**	**$2,621**
Nameplate Capacity (2) (megawatts)	**205**	**500**
Ownership	**25%**	**50%**

(1) Includes net plant acquisition adjustment.
(2) Total megawatt nameplate capacity:
Plant Scherer Unit No. 3: 818
Plant Daniel: 1,000

7. LONG-TERM POWER SALES AGREEMENTS

The Company and the other operating affiliates have long-term contractual agreements for the sale of capacity and energy to certain non-affiliated utilities located outside the system's service area. The unit power sales agreements are firm and pertain to capacity related to specific generating units. Because the energy is generally sold at cost under these agreements, profitability is primarily affected by revenues from capacity sales. The capacity revenues from these sales were $19.8 million in 1999, $22.5 million in 1998, and $24.9 million in 1997. Declining capacity revenues are due primarily to the decline in net plant investment related to these sales. In addition, the decline in 1999 reflects a reduction in the authorized rate of return on the equity component of the investment.

Unit power from specific generating plants of Southern Company is currently being sold to Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), Jacksonville Electric Authority (JEA), and the City of Tallahassee, Florida. Under these agreements, 214 megawatts of net dependable capacity were sold by the Company during 1999. Sales will decrease to 209 megawatts per year in 2000 and remain at that level -- unless reduced by FP&L, FPC, and JEA for the periods after 2000 with a minimum of three years notice -- until the expiration of the contracts in 2010.

Capacity and energy sales to FP&L, the Company's largest single customer, provided revenues of $24.3 million in 1999, $22.3 million in 1998, and $25.4 million in 1997, or 3.6 percent, 3.4 percent, and 4.1 percent of operating revenues, respectively.

8. INCOME TAXES

At December 31, 1999, the tax-related regulatory assets to be recovered from customers were $25.3 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 1999, the tax-related regulatory liabilities to be credited to customers were $49.7 million. 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 federal and state income tax provisions are as follows:

	1999	1998	1997
	(in thousands)		
Total provision for income taxes:			
Federal--			
Current	**$33,973**	$31,746	$34,522
Deferred --current year	**16,776**	18,485	19,297
--reversal of prior years	**(22,883)**	(22,952)	(25,778)
	27,866	27,279	28,041
State--			
Current	**5,267**	5,137	5,975
Deferred --current year	**2,474**	2,745	2,868
--reversal of prior years	**(2,976)**	(2,962)	(3,434)
	4,765	4,920	5,409
Total	**$32,631**	$32,199	$33,450

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:

	1999	1998
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$168,662**	$155,833
Property basis differences	**6,000**	20,330
Other	**18,272**	17,645
Total	**192,934**	193,808
Deferred tax assets:		
Federal effect of state deferred taxes	**9,293**	9,509
Postretirement benefits	**8,456**	7,644
Other	**12,526**	10,702
Total	**30,275**	27,855
Net deferred tax liabilities	**162,659**	165,953
Less current portion, net	**(117)**	(165)
Accumulated deferred income taxes in the Balance Sheets	**$162,776**	$166,118

Deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation and amortization in the Statements of Income. Credits amortized in this manner amounted to $1.9 million in 1999, $1.9 million in 1998, and $2.2 million in 1997. At December 31, 1999, 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:

	1999	1998	1997
Federal statutory rate	**35%**	35%	35%
State income tax, net of federal deduction	**4**	4	4
Non-deductible book depreciation	**1**	1	1
Difference in prior years' deferred and current tax rate	**(2)**	(2)	(1)
Other, net	**-**	(2)	(4)
Effective income tax rate	**38%**	36%	35%

The Company and the other subsidiaries of Southern Company file a consolidated federal tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis.

9. COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES

In January 1997, Gulf Power Capital Trust I (Trust I), of which the Company owns all of the common securities, issued $40 million of 7.625 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust I are $41 million aggregate principal amount of the Company's 7.625 percent junior subordinated notes due December 31, 2036.

In January 1998, Gulf Power Capital Trust II (Trust II), of which the Company owns all of the common securities, issued $45 million of 7.0 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust II are $46 million aggregate principal amount of the Company's 7.0 percent junior subordinated notes due December 31, 2037.

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 payment obligations with respect to the preferred securities of Trust I and Trust II. Trust I and Trust II are subsidiaries of the Company, and accordingly are consolidated in the Company's financial statements.

10. SECURITIES DUE WITHIN ONE YEAR

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

	1999	1998
	(in thousands)	
Bond improvement fund requirement	**$850**	$ 850
Less portion to be satisfied by certifying property additions	**850**	850
Cash requirement	**-**	-
Maturities of first mortgage bonds	**-**	-
Current portion of other long-term debt	**-**	27,000
Total	**$ -**	$27,000

The first mortgage bond improvement fund requirement amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control revenue bond obligations. The requirement may be satisfied by depositing cash, reacquiring bonds, or by pledging additional property equal to 1 and 2/3 times the requirement.

11. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture contains various common stock dividend restrictions which remain in effect as long as the bonds are outstanding. At December 31, 1999, retained earnings of $127 million were restricted against the payment of cash dividends on common stock under the terms of the mortgage indenture.

12. QUARTERLY FINANCIAL DATA (Unaudited)

Summarized quarterly financial data for 1999 and 1998 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 1999	**$134,506**	**$15,665**	**$ 4,799**
June 1999	**166,815**	**29,253**	**13,226**
September 1999	**218,264**	**54,429**	**28,582**
December 1999	**154,514**	**19,815**	**7,060**
March 1998	$140,950	$19,387	$ 6,853
June 1998	177,130	33,232	13,364
September 1998	199,377	49,837	26,989
December 1998	133,061	19,898	9,315

The Company's business is influenced by seasonal weather conditions and the timing of rate changes, among other factors.

ELECTED FINANCIAL AND OPERATING DATA 1995-1999
ulf Power Company 1999 Annual Report

	1999	1998	1997	1996	1995
perating Revenues (in thousands)	**$674,099**	$650,518	$625,856	$634,365	$619,077
et Income after Dividends					
on Preferred Stock (in thousands)	**$53,667**	$56,521	$57,610	$57,845	$57,154
ash Dividends					
on Common Stock (in thousands)	**$61,300**	$57,200	$64,600	$58,300	$46,400
eturn on Average Common Equity (percent)	**12.63**	13.20	13.33	13.27	13.27
otal Assets (in thousands)	**$1,308,495**	$1,267,901	$1,265,612	$1,308,366	$1,341,859
ross Property Additions (in thousands)	**$69,798**	$69,731	$54,289	$61,386	$63,113
apitalization (in thousands):					
ommon stock equity	**$422,313**	$427,652	$428,718	$435,758	$436,242
referred stock	**4,236**	4,236	13,691	65,102	89,602
ompany obligated mandatorily					
redeemable preferred securities	**85,000**	85,000	40,000	-	-
ong-term debt	**367,449**	317,341	296,993	331,880	323,376
otal (excluding amounts due within one year)	**$878,998**	$834,229	$779,402	$832,740	$849,220
apitalization Ratios (percent):					
ommon stock equity	**48.0**	51.3	55.0	52.3	51.4
referred stock	**0.5**	0.5	1.8	7.8	10.5
ompany obligated mandatorily					
redeemable preferred securities	**9.7**	10.2	5.1	-	-
ong-term debt	**41.8**	38.0	38.1	39.9	38.1
otal (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
ecurity Ratings:					
irst Mortgage Bonds -					
Moody's	**A1**	A1	A1	A1	A1
Standard and Poor's	**AA-**	AA-	AA-	A+	A+
Duff & Phelps	**AA-**	AA-	AA-	AA-	A+
referred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**A-**	A	A	A	A
Duff & Phelps	**A**	A+	A+	A+	A
nsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	-	-
Standard and Poor's	**A**	A	A	-	-
Duff & Phelps	**A+**	A+	A+	-	-
ustomers (year-end):					
esidential	**315,240**	307,077	300,257	291,196	283,421
ommercial	**47,728**	46,370	44,589	43,196	41,281
ndustrial	**267**	257	267	278	278
ther	**316**	268	264	162	134
otal	**363,551**	353,972	345,377	334,832	325,114
mployees (year-end):	**1,339**	1,328	1,328	1,384	1,501

SELECTED FINANCIAL AND OPERATING DATA 1995-1999 (continued)

Gulf Power Company 1999 Annual Report

	1999	1998	1997	1996	1995
Operating Revenues (in thousands):					
Residential	**$ 277,311**	$276,208	$ 277,609	$ 285,498	$ 276,155
Commercial	**165,871**	160,960	164,435	164,181	159,260
Industrial	**67,404**	69,850	77,492	78,994	81,606
Other	**2,174**	2,100	2,083	2,056	1,993
Total retail	**512,760**	509,118	521,619	530,729	519,014
Sales for resale - non-affiliates	**62,354**	61,893	63,697	63,201	60,413
Sales for resale - affiliates	**66,110**	42,642	16,760	17,762	18,619
Total revenues from sales of electricity	**641,224**	613,653	602,076	611,692	598,046
Other revenues	**32,875**	36,865	23,780	22,673	21,031
Total	**$674,099**	$650,518	$625,856	$634,365	$619,077
Kilowatt-Hour Sales (in thousands):					
Residential	**4,471,118**	4,437,558	4,119,492	4,159,924	4,014,142
Commercial	**3,222,532**	3,111,933	2,897,887	2,808,634	2,708,243
Industrial	**1,846,237**	1,833,575	1,903,050	1,808,086	1,794,754
Other	**19,296**	18,952	18,101	17,815	17,345
Total retail	**9,559,183**	9,402,018	8,938,530	8,794,459	8,534,484
Sales for resale - non-affiliates	**1,561,972**	1,341,990	1,531,179	1,534,097	1,396,474
Sales for resale - affiliates	**2,511,983**	1,758,150	848,135	709,647	759,341
Total	**13,633,138**	12,502,158	11,317,844	11,038,203	10,690,299
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**6.20**	6.22	6.74	6.86	6.88
Commercial	**5.15**	5.17	5.67	5.85	5.88
Industrial	**3.65**	3.81	4.07	4.37	4.55
Total retail	**5.36**	5.41	5.84	6.03	6.08
Sales for resale	**3.15**	3.37	3.38	3.61	3.67
Total sales	**4.70**	4.91	5.32	5.54	5.59
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,318**	14,577	13,894	14,457	14,148
Residential Average Annual Revenue Per Customer	**$888.01**	$907.35	$936.30	$992.17	$973.35
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,188**	2,188	2,174	2,174	2,174
Maximum Peak-Hour Demand Net of SEPA (megawatts):					
Winter	**2,085**	2,040	1,844	2,136	1,732
Summer	**2,161**	2,146	2,032	1,961	2,040
Annual Load Factor (percent)	**55.2**	55.3	55.5	51.4	53.0
Plant Availability Fossil-Steam (percent):	**87.2**	87.6	91.0	91.8	84.0
Source of Energy Supply (percent):					
Coal	**89.8**	89.2	87.1	87.8	86.8
Oil and gas	**2.5**	2.0	0.4	0.5	0.4
Purchased power -					
From non-affiliates	**5.9**	5.5	3.5	2.7	4.0
From affiliates	**1.8**	3.3	9.0	9.0	8.8
Total	**100.0**	100.0	100.0	100.0	100.0

OFFICERS

Travis J. Bowden
President and Chief Executive Officer
Age 61; 24 Years of Service

Francis M. Fisher, Jr.
Vice President - Power Delivery
and Customer Operations
Age 51; 28 Years of Service

John E. Hodges, Jr.
Vice President - Marketing and
Employee/External Affairs
Age 56; 33 Years of Service

Robert G. Moore
Vice President – Power Generation
and Transmission
Age 50; 26 Years of Service

Arlan E. Scarbrough
Vice President - Finance
Age: 63; 37 Years of Service

Ronnie R. Labrato
Controller
Age 46; 20 Years of Service

Warren E. Tate
Secretary and Treasurer
Age 57; 35 Years of Service

Susan D. Ritenour
Assistant Secretary and
Assistant Treasurer
Age 40; 18 Years of Service

Linda G. Malone
Assistant Secretary and
Assistant Treasurer
Age 50; 29 Years of Service

C. Alan Martin
Vice President
Age 51; 27 Years of Service

Michael L. Scott
Vice President
Age 46; 23 Years of Service

Christopher C. Womack
Vice President
Age 41; 11 Years of Service

E. Wayne Boston
Assistant Secretary and
Assistant Treasurer
Age 55; 29 Years of Service

DIRECTORS

H. Allen Franklin (1)
President and Chief Operating Officer
Southern Company
Atlanta, Georgia. Elected 1999

Paul J. DeNicola (2)
President and Chief Executive Officer
Southern Company Services, Inc.
Atlanta, Georgia. Elected 1991

Travis J. Bowden
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 1994

Fred C. Donovan, Sr.
President
Baskerville-Donovan, Inc.
Pensacola, Florida. Elected 1991

W. Deck Hull, Jr.
President
Hull Company
Panama City, Florida. Elected 1983

Joseph K. Tannehill
President and Chief Executive Officer
Tannehill International Industries
Lynn Haven, Florida. Elected 1985

Barbara H. Thames
Chief Operating Officer
West Florida Regional Medical Center
Pensacola, Florida. Elected 1997

Advisory Director

Douglas L. McCrary (3)
Retired Chairman of the Board and
Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 1994

(1) Election effective
June 29, 1999
(2) Retirement effective
July 1, 1999
(3) Retirement effective
April 24, 1999

Profile
Gulf Power Company is an investor-owned electric utility serving 363,551 customers in 10 counties in the Florida panhandle. The service territory spans 7,400 square miles in 71 communities and rural areas. The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, Southern Company Services, Inc., Southern Energy, Inc., Southern Nuclear Operating Company, Southern Company Energy Solutions, Inc. and other direct and indirect subsidiaries.

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

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.

Registrar, Transfer Agent, and Dividend Paying Agent
All series of Preferred Stock
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

Trustee, Registrar, and Interest Paying Agent
All series of First Mortgage Bonds and Trust Preferred Securities
The Chase Manhattan Bank
Global Trust Services
450 West 33rd Street
New York, NY 10001-2697

Corporate Office
Principal Address & Deliveries:
Gulf Power Company
500 Bayfront Parkway
Pensacola, FL 32520
(850) 444-6111

Mailing Address:
Gulf Power Company
One Energy Place
Pensacola, FL 32520

Auditors
Arthur Andersen LLP
133 Peachtree Street, N.E.
Atlanta, GA 30303

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
Pensacola, FL 32576-2950

Schedule F-3	SEC REPORTS	Page 1 of 1
FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 010949-EI	EXPLANATION: Provide a copy of the most recent Form 10-K annual report to the Securities and Exchange Commission and all Form 10-Q quarterly reports filed subsequesnt to the filing of the latest 10-K.	Type of Data Shown: __ Projected Test Year Ended 5/31/03 __ Prior Year Ended 5/31/02 XX Historical Year 12/31/00 Witness: R. R. Labrato

See Attached.

Supporting Schedules:

Recap Schedules:

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

FORM 10-K

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2000
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 270 Peachtree Street, N.W. Atlanta, Georgia 30303 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
0-2429	**Gulf Power Company** (A Maine Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
0-6849	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
1-5072	**Savannah Electric and Power Company** (A Georgia Corporation) 600 East Bay Street Savannah, Georgia 31401 (912) 644-7171	58-0418070

Securities registered pursuant to Section 12(b) of the Act:[1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is registered on the New York Stock Exchange.

Title of each class	Registrant
Common Stock, $5 par value	**The Southern Company**
Company obligated mandatorily redeemable preferred securities, $25 liquidation amount 7.75% Cumulative Quarterly Income Preferred Securities[2] 7 1/8% Trust Originated Preferred Securities[3] 6.875% Cumulative Quarterly Income Preferred Securities[4]	
Class A preferred, cumulative, $25 stated capital 5.20% Series; 5.83% Series	**Alabama Power Company**
Senior Notes 7 1/8% Series A; 7% Series C 7% Series B; 6.75% Series J	
Company obligated mandatorily redeemable preferred securities, $25 liquidation amount 7.375% Trust Preferred Securities[5] 7.60% Trust Originated Preferred Securities[6]	
Senior Notes 6 7/8% Series A; 6 5/8% Series D 6.60% Series B	**Georgia Power Company**
Company obligated mandatorily redeemable preferred securities, $25 liquidation amount 7.75% Trust Preferred Securities[7] 7.75% Cumulative Quarterly Income Preferred Securities[9] 7.60% Trust Preferred Securities[8] 6.85% Trust Preferred Securities[10]	

[1] As of December 31, 2000.
[2] Issued by Southern Company Capital Trust III and guaranteed by The Southern Company.
[3] Issued by Southern Company Capital Trust IV and guaranteed by The Southern Company.
[4] Issued by Southern Company Capital Trust V and guaranteed by The Southern Company.
[5] Issued by Alabama Power Capital Trust I and guaranteed by Alabama Power Company.
[6] Issued by Alabama Power Capital Trust II and guaranteed by Alabama Power Company.
[7] Issued by Georgia Power Capital Trust I and guaranteed by Georgia Power Company.
[8] Issued by Georgia Power Capital Trust II and guaranteed by Georgia Power Company.
[9] Issued by Georgia Power Capital Trust III and guaranteed by Georgia Power Company.
[10] Issued by Georgia Power Capital Trust IV and guaranteed by Georgia Power Company.

Company obligated mandatorily redeemable preferred securities, $25 liquidation amount 7.625% Cumulative Quarterly Income Preferred Securities[11] 7.00% Cumulative Quarterly Income Preferred Securities[12]	**Gulf Power Company**
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 6.32% Series 6.65% Series **Company obligated mandatorily redeemable preferred securities, $25 liquidation amount** 7.75% Trust Originated Preferred Securities[13]	**Mississippi Power Company**
Company obligated mandatorily redeemable preferred securities, $25 liquidation amount 6.85% Trust Preferred Securities[14]	**Savannah Electric and Power Company**

Securities registered pursuant to Section 12(g) of the Act:[15]

Title of each class	Registrant
Preferred stock, cumulative, $100 par value 4.20% Series 4.60% Series 4.72% Series 4.52% Series 4.64% Series 4.92% Series **Class A preferred, cumulative, $100,000 stated capital** Auction (1993 Series) **Class A preferred, cumulative, $100 stated capital** Auction (1988 Series)	**Alabama Power Company**
Preferred stock, cumulative, $100 stated value $4.60 Series (1954)	**Georgia Power Company**

[11] Issued by Gulf Power Capital Trust I and guaranteed by Gulf Power Company.
[12] Issued by Gulf Power Capital Trust II and guaranteed by Gulf Power Company.
[13] Issued by Mississippi Power Capital Trust I and guaranteed by Mississippi Power Company.
[14] Issued by Savannah Electric Capital Trust I and guaranteed by Savannah Electric and Power Company.
[15] As of December 31, 2000.

Preferred stock, cumulative, $100 par value

4.64% Series	5.44% Series	**Gulf Power Company**
5.16% Series		

Preferred stock, cumulative, $100 par value

4.40% Series	4.60% Series	**Mississippi Power Company**
4.72% Series	7.00% Series	

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes _X_ No___

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

Aggregate market value of voting stock held by non-affiliates of The Southern Company at February 28, 2001: $21.1 billion. Each of such other registrants is a wholly-owned subsidiary of The Southern Company. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 28, 2001
The Southern Company	Par Value $5 Per Share	681,946,097
Alabama Power Company	Par Value $40 Per Share	5,608,955
Georgia Power Company	No Par Value	7,761,500
Gulf Power Company	No Par Value	992,717
Mississippi Power Company	Without Par Value	1,121,000
Savannah Electric and Power Company	Par Value $5 Per Share	10,844,635

Documents incorporated by reference: specified portions of The Southern Company's Proxy Statement relating to the 2001 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Information Statements of Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company relating to each of their respective 2001 Annual Meetings of Shareholders are incorporated by reference into PART III.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in Items 1 through 5 and Items 10 through 14, the following terms will have the meanings indicated.

Term	Meaning
AEC	Alabama Electric Cooperative, Inc.
AFUDC	Allowance for Funds Used During Construction
ALABAMA	Alabama Power Company
AMEA	Alabama Municipal Electric Authority
Clean Air Act	Clean Air Act Amendments of 1990
Dalton	City of Dalton, Georgia
DOE	United States Department of Energy
EMF	Electromagnetic field
Energy Act	Energy Policy Act of 1992
Energy Solutions	Southern Company Energy Solutions, Inc.
Entergy Gulf States	Entergy Gulf States Utilities Company
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FPC	Florida Power Corporation
FP&L	Florida Power & Light Company
GEORGIA	Georgia Power Company
GULF	Gulf Power Company
Holding Company Act	Public Utility Holding Company Act of 1935, as amended
IBEW	International Brotherhood of Electrical Workers
integrated Southeast utilities	ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH
IPP	Independent power producer
IRS	Internal Revenue Service
JEA	Jacksonville Electric Authority
MEAG	Municipal Electric Authority of Georgia
MESH	Mobile Energy Services Holdings
Mirant	Mirant Corporation (formerly Southern Energy, Inc.)
MISSISSIPPI	Mississippi Power Company
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
PSC	Public Service Commission
RTO	Regional Transmission Organization
RUS	Rural Utility Service (formerly Rural Electrification Administration)

DEFINITIONS
(continued)

SAVANNAH	Savannah Electric and Power Company
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
SOUTHERN	The Southern Company
Southern LINC	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
SOUTHERN system	SOUTHERN, the integrated Southeast utilities, SEGCO, Southern Nuclear, SCS, Southern LINC, Energy Solutions and other subsidiaries
Southern Telecom	Southern Telecom, Inc.
SPC	Southern Power Company
TVA	Tennessee Valley Authority

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking and historical information. Forward-looking information includes, among other things, statements concerning the strategic goals for SOUTHERN's new wholesale business and also SOUTHERN's earnings per share and earnings growth goals. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of these terms or other comparable terminology. The registrants caution 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 SOUTHERN and its subsidiaries are subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action against certain of the integrated Southeast utilities and the race discrimination litigation against certain of SOUTHERN's subsidiaries; the extent and timing of the entry of additional competition in the markets of SOUTHERN's subsidiaries; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options that may be pursued by SOUTHERN; state and federal rate regulation in the United States and in foreign countries in which SOUTHERN's subsidiaries operate; political, legal and economic conditions and developments in the United States and in foreign countries in which SOUTHERN's subsidiaries operate; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the performance of projects undertaken by the non-traditional business and the success of efforts to invest in and develop new opportunities; the timing and acceptance of SOUTHERN's new product and service offerings; the ability of SOUTHERN to obtain additional generating capacity at competitive prices; developments in the California power markets, including, but not limited to, governmental intervention, deterioration in the financial condition of counterparties, default on receivables due, adverse results in current or future litigation and adverse changes in the tariffs of the California Power Exchange Corporation or the California Independent System Operator Corporation; and other factors discussed elsewhere herein and in other reports filed from time to time with the SEC.

PART I

Item 1. BUSINESS

SOUTHERN was incorporated under the laws of Delaware on November 9, 1945. SOUTHERN is domesticated under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. SOUTHERN owns all the outstanding common stock of ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH, each of which is an operating public utility company. The integrated Southeast utilities supply electric service in the states of Alabama, Georgia, Florida, Mississippi and Georgia, respectively. More particular information relating to each of the integrated Southeast utilities is as follows:

ALABAMA is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company and Houston Power Company. The predecessor Alabama Power Company had had a continuous existence since its incorporation in 1906.

GEORGIA was incorporated under the laws of the State of Georgia on June 26, 1930, and admitted to do business in Alabama on September 15, 1948.

GULF is a corporation which was organized under the laws of the State of Maine on November 2, 1925, and admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984.

MISSISSIPPI was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924, and was admitted to do business in Mississippi on December 23, 1924, and in Alabama on December 7, 1962.

SAVANNAH is a corporation existing under the laws of the State of Georgia; its charter was granted by the Secretary of State on August 5, 1921.

SOUTHERN also owns all the outstanding common stock of Southern LINC, Southern Nuclear, SCS, Energy Solutions, Southern Telecom, SPC and other direct and indirect subsidiaries. Southern LINC provides digital wireless communications services to SOUTHERN's integrated Southeast utilities and also markets these services to the public within the Southeast. Southern Nuclear provides services to ALABAMA's and GEORGIA's nuclear plants. Energy Solutions develops new business opportunities related to energy products and services. Southern Telecom provides wholesale fiber optic solutions to telecommunication providers in the Southeastern United States. SPC, formed in January 2001, will be the primary growth engine for SOUTHERN's market-based energy business.

ALABAMA and GEORGIA each own 50% of the outstanding common stock of SEGCO. SEGCO owns electric generating units with an aggregate capacity of 1,019,680 kilowatts at Plant Gaston on the Coosa River near Wilsonville, Alabama, and ALABAMA and GEORGIA are each entitled to one-half of SEGCO's capacity and energy. ALABAMA acts as SEGCO's agent in the operation of SEGCO's units and furnishes coal to SEGCO as fuel for its units. SEGCO also owns three 230,000 volt transmission lines extending from Plant Gaston to the Georgia state line at which point connection is made with the GEORGIA transmission line system.

Reference is also made to Note 12 to the financial statements of SOUTHERN in Item 8 herein for additional information regarding SOUTHERN's segment and related information.

Mirant Corporation

Previously, SOUTHERN owned all the outstanding common stock of Mirant. In April 2000, SOUTHERN announced an initial public offering of up to 19.9 percent of Mirant and its intentions to spin off the remaining ownership of Mirant to SOUTHERN's common stockholders within 12 months of the initial stock offering. On October 2, 2000, Mirant completed an initial public offering of 66.7 million shares. On February 19, 2001, SOUTHERN's board of directors approved the spin off of the remaining ownership of 272 million Mirant shares to be completed in a tax free distribution on April 2, 2001. As a result of the spin off, SOUTHERN's financial statements and related information in Item 8 herein reflect Mirant as discontinued operations.

The SOUTHERN System

Integrated Southeast Utilities

The transmission facilities of each of the integrated Southeast utilities are connected to the respective company's own generating plants and other sources of power and are interconnected with the transmission facilities of the other integrated Southeast utilities and SEGCO by means of heavy-duty high voltage lines. (In the case of GEORGIA's integrated transmission system, see Item 1 - BUSINESS - "Territory Served by the Integrated Southeast Utilities" herein.)

Operating contracts covering arrangements in effect with principal neighboring utility systems provide for capacity exchanges, capacity purchases and sales, transfers of economy energy and other similar transactions. Additionally, the integrated Southeast utilities have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group and TVA and with Carolina Power & Light Company, Duke Energy Corporation, South Carolina Electric & Gas Company and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The integrated Southeast utilities have joined with other utilities in the Southeast (including those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the integrated Southeast utilities are represented on the National Electric Reliability Council.

An intra-system interchange agreement provides for coordinating operations of the power producing facilities of the integrated Southeast utilities and the capacities available to such companies from non-affiliated sources and for the pooling of surplus energy available for interchange. Coordinated operation of the entire interconnected system is conducted through a central power supply coordination office maintained by SCS. The available sources of energy are allocated to the integrated Southeast utilities to provide the most economical sources of power consistent with good operation. The resulting benefits and savings are apportioned among the integrated Southeast utilities.

On December 20, 1999, the FERC issued its final rule on RTOs ("Order 2000"). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Utilities were required to make a filing with the FERC by October 16, 2000 explaining how they would respond to Order 2000 consistent with this requirement. On October 16, 2000, SOUTHERN filed its RTO proposal. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of SOUTHERN and other participating utilities in the region. Participants would have the option to either maintain their ownership, divest, sell or lease their transmission assets to the proposed RTO. On March 14, 2001, the FERC rejected SOUTHERN's proposal on the grounds that the limitation of the scope of services to new wholesale transmission and the provision of incentives to passive owners were inconsistent with Order 2000. This order requires a status report from SOUTHERN by May 14, 2001, but does not establish a deadline for SOUTHERN to file a revised petition. Reference is made to each registrant's "Management's Discussion and Analysis – Future Earnings Potential" in Item 7 for additional information.

SCS has contracted with SOUTHERN, each integrated Southeast utility, Mirant, various of the other subsidiaries, Southern Nuclear and SEGCO to furnish, at cost and upon request, the following services: general executive and advisory services, power pool operations, general engineering, design engineering, purchasing, accounting, finance and treasury, taxes, insurance and pensions, corporate, rates, budgeting, public relations, employee relations, systems and procedures and other services with respect to business and operations. Energy Solutions and Southern LINC have also secured from the integrated Southeast utilities certain services which are furnished at cost.

Southern Nuclear has contracts with ALABAMA to operate the Farley Nuclear Plant, and with GEORGIA to operate Plants Hatch and Vogtle. See Item 1 - BUSINESS - "Regulation - Atomic Energy Act of 1954" herein.

Other Business

Energy Solutions focuses on new and existing programs to enhance customer satisfaction, efficiency and stockholder value. Examples are: Good Cents, an energy efficiency program for electric utility customers; Energy Services, an energy solutions consultant and contractor for industrial and large commercial customers; and Bill Payment Protection, an insurance product that protects a residential customer by paying the electric bill in the event the customer becomes involuntarily unemployed, disabled, or goes on unpaid leave.

In 1996, Southern LINC began serving SOUTHERN's integrated Southeast utilities and marketing its services to non-affiliates within the Southeast. Its system covers approximately 127,000 square miles and combines the functions of two-way radio dispatch, cellular phone, short text and numeric messaging and wireless data transfer.

These continuing efforts to invest in and develop new business opportunities offer the potential of earning returns which may exceed those of rate-regulated operations. However, these activities also involve a higher degree of risk. SOUTHERN expects to make substantial investments over the period 2001-2003 in these and other new businesses.

In 1999, MESH, a subsidiary of SOUTHERN, filed a petition for Chapter 11 bankruptcy relief in the U.S. Bankruptcy Court. On August 4, 2000, MESH filed a proposed plan of reorganization with the bankruptcy court that was amended on September 15, 2000. The proposed plan of reorganization was again amended on February 21, 2001. Reference is made to Note 3 to the financial statements of SOUTHERN in Item 8 herein for additional information relating to this matter.

Certain Factors Affecting the Industry

Various factors are currently affecting the electric utility industry in general, including increasing competition and the regulatory changes related thereto, costs required to comply with environmental regulations, and the potential for new business opportunities (with their associated risks) outside of traditional rate-regulated operations. The effects of these and other factors on the SOUTHERN system are described herein. Particular reference is made to Item 1 - BUSINESS - "Other Business", "Competition" and "Environmental Regulation." See also "Cautionary Statement Regarding Forward-Looking Information."

Construction Programs

The subsidiary companies of SOUTHERN are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. Construction additions or acquisitions of property during 2001 through 2003 by the integrated Southeast utilities, SEGCO, SCS, Southern LINC and other subsidiaries are estimated as follows: (in millions)

	2001	2002	2003
ALABAMA	$ 735	$ 891	$ 625
GEORGIA	1,613	1,349	785
GULF	279	96	76
MISSISSIPPI	62	60	69
SAVANNAH	33	31	32
SEGCO	16	17	16
SCS	29	21	21
Southern LINC	26	39	26
Other	111	60	1
SOUTHERN system	$2,904	$2,564	$1,651

Included in these estimated totals are expenditures for construction of wholesale generation assets that may be transferred to SPC. Assuming such transfers are made, SPC's projected construction program expenditures are approximately $1.2 billion in 2001, $725 million in 2002, and $452 million in 2003.

Estimated construction costs in 2001 are expected to be apportioned approximately as follows: (in millions)

	SOUTHERN system*	ALABAMA	GEORGIA	GULF	MISSISSIPPI	SAVANNAH
New generation	$ 940	$169	$ 596	$172	$ 3	$ -
Other generating facilities including associated plant substations	682	181	433	35	10	7
New business	368	129	188	22	19	10
Transmission	340	110	189	21	14	6
Joint line and substation	47	-	34	13	-	-
Distribution	184	68	85	12	11	8
Nuclear fuel	93	38	55	-	-	-
General plant	250	40	33	4	5	2
	$2,904	$735	$1,613	$279	$62	$33

*Southern LINC, SCS, and other businesses plan capital additions to general plant in 2001 of $26 million, $29 million, and $111 million, respectively, while SEGCO plans capital additions of $16 million to generating facilities. (See Item 1 - BUSINESS - "Other Business" herein.)

The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; acquisitions of additional generating assets; 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. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

SOUTHERN has approximately 6,600 megawatts of new generating capacity scheduled to be placed in service by 2003. Approximately 4,400 megawatts of additional new capacity will be dedicated to the wholesale market and owned by SPC.

In 1991, the Georgia legislature passed legislation which requires GEORGIA and SAVANNAH each to file an Integrated Resource Plan for approval by the Georgia PSC. Under the plan rules, the Georgia PSC must pre-certify the construction of new power plants and new purchase power contracts. (See Item 1 - BUSINESS - "Rate Matters - Integrated Resource Planning" herein.)

See Item 1 - BUSINESS - "Regulation - Environmental Regulation" herein for information with respect to certain existing and proposed environmental requirements and Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein for additional information concerning ALABAMA's and GEORGIA's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

The amount and timing of additional equity capital to be raised in 2001, as well as subsequent years, will be contingent on SOUTHERN's investment opportunities. Equity capital can be provided from any combination of public offerings, private placements, or SOUTHERN's stock plans.

The integrated Southeast utilities plan 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. Recently, the integrated Southeast utilities have relied on the issuance of unsecured debt and trust preferred securities, in addition to unsecured pollution control bonds issued for its benefit by public authorities to meet its long-term external financing requirements. In years past, the integrated Southeast utilities issued first mortgage bonds, mortgage backed pollution control bonds and preferred stock to fund its external requirements. The amount outstanding of the latter securities has been declining in recent years.

If the integrated Southeast utilities were to choose to issue new first mortgage bonds or preferred stock once again, they would be required to meet certain coverage requirements.

Short-term debt is often utilized as appropriate at SOUTHERN and the integrated Southeast utilities.

The maximum amounts of short-term and term-loan indebtedness authorized by the appropriate regulatory authorities are shown on the following table:

	Amount Authorized	Outstanding at December 31, 2000
	(in millions)	
ALABAMA	$ 750 (1)	$ 281
GEORGIA	1,700 (2)	704
GULF	300(1)	43
MISSISSIPPI	350(1)	56
SAVANNAH	160(2)	75
SOUTHERN	2,000(1)	550

Notes:

(1) ALABAMA's authority is based on authorization received from the Alabama PSC, which expires December 31, 2001. No SEC authorization is required for ALABAMA. GULF, MISSISSIPPI and SOUTHERN have received SEC authorization to issue from time to time short-term and/or term-loan notes to banks and commercial paper to dealers in the amounts shown through December 31, 2003, December 31, 2002 and March 31, 2008, respectively.

(2) GEORGIA and SAVANNAH have received SEC authorization to issue from time to time short-term and term-loan notes to banks and commercial paper to dealers in the amounts shown through December 31, 2002. Authorization for term-loan indebtedness is also required by the Georgia PSC. SAVANNAH received authority from the Georgia PSC for $70 million in term loans expiring January 31, 2002.

Reference is made to Note 8 to the financial statements for SOUTHERN, Note 4 to the financial statements for ALABAMA, GULF, MISSISSIPPI and SAVANNAH and Note 9 to the financial statements for GEORGIA in Item 8 herein for information regarding the registrants' credit arrangements.

Fuel Supply

The integrated Southeast utilities' and SEGCO's supply of electricity is derived predominantly from coal. The sources of generation for the years 1998 through 2000 and the estimates for 2001 are shown below:

	Coal	Nuclear	Hydro	Oil and Gas
ALABAMA				
1998	72	18	8	2
1999	72	20	5	3
2000	72	19	3	6
2001	70	16	5	9
GEORGIA				
1998	73	22	3	2
1999	75	22	1	2
2000	76	21	1	2
2001	75	21	3	1
GULF				
1998	98	**	**	2
1999	97	**	**	3
2000	98	**	**	2
2001	98	**	**	2
MISSISSIPPI				
1998	80	**	**	20
1999	81	**	**	19
2000	83	**	**	17
2001	78	**	**	22
SAVANNAH				
1998	76	**	**	24
1999	78	**	**	22
2000	88	**	**	12
2001	85	**	**	15
SEGCO				
1998	100	**	**	*
1999	100	**	**	*
2000	100	**	**	*
2001	100	**	**	*
SOUTHERN system* **				
1998	76	16	4	4
1999	78	17	2	3
2000	76	16	4	4
2001	76	15	3	6

*Less than 0.5%.
**Not applicable.
***Amounts shown for the SOUTHERN system are weighted averages of the integrated Southeast utilities and SEGCO.

The average costs of fuel in cents per net kilowatt-hour generated for 1998 through 2000 are shown below:

	1998	1999	2000
ALABAMA	1.54	1.44	1.54
GEORGIA	1.36	1.34	1.39
GULF	1.69	1.60	1.68
MISSISSIPPI	1.62	1.65	1.80
SAVANNAH	2.33	2.20	2.28
SEGCO	1.53	1.77	1.51
SOUTHERN System*	1.48	1.45	1.51

* Amounts shown for the SOUTHERN system are weighted averages of the integrated Southeast utilities and SEGCO.

See SELECTED FINANCIAL DATA in Item 6 herein for each registrant's source of energy supply.

As of February 9, 2001, the integrated Southeast utilities had stockpiles of coal on hand at their respective coal-fired plants which represented an estimated 23 days of recoverable supply for bituminous coal and 31 days for sub-bituminous coal. It is estimated that approximately 68 million tons of coal will be consumed in 2001 by the integrated Southeast utilities (including those units GEORGIA owns jointly with OPC, MEAG and Dalton and operates for FP&L and JEA and the units ALABAMA owns jointly with AEC). The integrated Southeast utilities currently have 60 coal contracts. These contracts cover remaining terms of up to 12 years. Approximately 15% of 2001 estimated coal requirements will be purchased in the spot market. Additionally, it has been determined that approximately 34 normal full load days of recoverable supply is desirable at the beginning of the heavy burn season between June 1 and September 30 with 31 normal full load days being the average annual target.

In 2000, the weighted average sulfur content of all coal purchased by the integrated Southeast utilities for use in the coal-fired facilities was 0.77% sulfur. This sulfur level, along with banked sulfur dioxide allowances, allowed the integrated Southeast utilities and SEGCO to remain within limits as set forth by Phase II of the Clean Air Act. As more and more strict environmental regulations are proposed that impact the utilization of coal, the fuel mix will be monitored to insure that sufficient quantities of the proper type of coal or natural gas are in place to remain in compliance with applicable laws and regulations. See Item 1 - BUSINESS - "Regulation - Environmental Regulation" herein.

Changes in fuel prices are generally reflected in fuel adjustment clauses contained in rate schedules. See Item 1 - BUSINESS - "Rate Matters - Rate Structure" herein.

ALABAMA and GEORGIA have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services and fuel fabrication. These contracts have varying expiration dates and most are short to medium term (less than 10 years). Management believes that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the SOUTHERN system's nuclear generating units.

ALABAMA and GEORGIA have contracts with the DOE that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in January 1998, as required by the contracts, and the companies are pursuing legal remedies against the government for breach of contract. Effective June 2000, an on-site dry storage facility for Plant Hatch became operational. Sufficient capacity is believed to be available to continue dry storage operations at Plant Hatch through the life of the plant. Sufficient fuel storage capacity currently is available at Plant Vogtle to maintain full-core discharge capability for both units into the year 2014. 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 as early as 2005.

The Energy Act imposed upon utilities with nuclear plants, including ALABAMA and GEORGIA, obligations for the decontamination and decommissioning of federal nuclear fuel enrichment facilities. See Note 1 to SOUTHERN's, ALABAMA's and GEORGIA's financial statements in Item 8 herein.

Territory Served by the Integrated Southeast Utilities

The territory in which the integrated Southeast utilities provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems which obtain some or all of their power requirements either directly or indirectly from the integrated Southeast utilities. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 11 million.

ALABAMA is engaged, within the State of Alabama, in the generation and purchase of electricity and the distribution and sale of such electricity at retail in over 1,000 communities (including Anniston, Birmingham, Gadsden, Mobile, Montgomery and Tuscaloosa) and at wholesale to 15 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. ALABAMA also supplies steam service in downtown Birmingham. ALABAMA also sells, and cooperates with dealers in promoting the sale of, electric appliances.

GEORGIA is engaged in the generation and purchase of electricity and the distribution and sale of such electricity within the State of Georgia at retail in over 600 communities, as well as in rural areas, and at wholesale currently to OPC, MEAG, the City of Dalton and the City of Hampton.

GULF is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the distribution and sale of such electricity at retail in 71 communities (including Pensacola, Panama City and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility and a municipality.

MISSISSIPPI is engaged in the generation and purchase of electricity and the distribution and sale of such energy within the 23 counties of southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations and one generating and transmitting cooperative.

SAVANNAH is engaged, within a five-county area in eastern Georgia, in the generation and purchase of electricity and the distribution and sale of such electricity at retail and, as a member of the SOUTHERN system power pool, the transmission and sale of wholesale energy.

For information relating to kilowatt-hour sales by classification for each registrant, reference is made to "Management's Discussion and Analysis-Results of Operations" in Item 7 herein. Also, for information relating to the sources of revenues for the SOUTHERN system and each of the integrated Southeast utilities, reference is made to Item 6 herein.

A portion of the area served by the integrated Southeast utilities adjoins the area served by TVA and its municipal and cooperative distributors. An Act of Congress limits the distribution of TVA power, unless otherwise authorized by Congress, to specified areas or customers which generally were those served on July 1, 1957.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the integrated Southeast utilities provide electric service at retail or wholesale.

One of these, AEC, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems and other customers in south Alabama and northwest Florida. AEC owns generating units with approximately 840 megawatts of nameplate capacity, including an undivided ownership interest in ALABAMA's Plant Miller Units 1 and 2. AEC's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from AEC to the extent such energy is available. Two of the 14 distributing cooperatives operating in ALABAMA's service territory obtain a portion of their power requirements directly from ALABAMA.

Four electric cooperative associations, financed by the RUS, operate within GULF's service area. These cooperatives purchase their full requirements from AEC and SEPA (a federal power marketing agency). A non-affiliated utility also operates within GULF's service area and purchases its full requirements from GULF.

ALABAMA and GULF have entered into separate agreements with AEC involving interconnection between the respective systems. The delivery of capacity and energy from AEC to certain distributing cooperatives in the service areas of ALABAMA and GULF is governed by the SOUTHERN/AEC Network Transmission Service Agreement. The rates for this service to AEC are based on the negotiated agreement on file with the FERC. See Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein for details of ALABAMA's joint-ownership with AEC of a portion of Plant Miller.

MISSISSIPPI has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by MISSISSIPPI to SMEPA. SMEPA has a generating capacity of 821 megawatts and a transmission system estimated to be 1,480 miles in length.

There are 43 electric cooperative organizations operating in, or in areas adjoining, territory in the State of Georgia in which GEORGIA provides electric service at retail or wholesale. Three of these organizations obtain their power from TVA and one from other sources. Since July 1, 1975, OPC has supplied the requirements of the remaining 39 of these cooperative organizations from self-owned generation acquired from GEORGIA and, until September 1991, through partial requirements purchases from GEORGIA. GEORGIA entered into a power coordination agreement with OPC pursuant to which, effective in September 1991, OPC ceased to be partial requirements wholesale customer of GEORGIA. Instead, OPC began the purchase of 1,250 megawatts of capacity from GEORGIA through 1999, subject to reduction or extension by OPC, and may satisfy the balance of its needs through purchases from others. OPC decreased its purchases of capacity by 250 megawatts each in September 1997, 1998 and 1999. Under the amended 1995 Integrated Resource Plan approved by the Georgia PSC in March 1997, the resources associated with the decreased purchases by OPC in 1997, 1998 and 1999 will be used to meet the needs of GEORGIA's retail customers through 2004. In April 1999, a new power supply agreement was implemented between GEORGIA and OPC. Pursuant to this agreement, OPC will purchase 250 megawatts of steam capacity through March 2006, 250 megawatts of peaking capacity through August 2000, and 125 megawatts of peaking capacity from September 2000 through August 2001.

There are 65 municipally-owned electric distribution systems operating in the territory in which the integrated Southeast utilities provide electric service at retail or wholesale.

AMEA was organized under an act of the Alabama legislature and is comprised of 11 municipalities. In 1986, ALABAMA entered into a firm power purchase contract with AMEA entitling AMEA to scheduled amounts of capacity (to a maximum of 100 megawatts) for a period of 15 years commencing September 1, 1986. In October 1991, ALABAMA entered into a second firm power purchase contract with AMEA entitling AMEA to scheduled amounts of additional capacity (to a maximum 80 megawatts) for a period of 15 years commencing October 1, 1991. In both contracts, the power is being sold to AMEA for its member municipalities that previously were served directly by ALABAMA as wholesale customers. Under the terms of the contracts, ALABAMA received payments from AMEA representing the net present value of the revenues associated with the respective capacity entitlements. See Note 6 to ALABAMA's financial statements in Item 8 herein for further information on these contracts.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG, which was established by a state statute in 1975. MEAG serves these requirements from self-owned generation facilities acquired from GEORGIA and purchases from others. In August 1997, a power coordination agreement was implemented between GEORGIA and MEAG that replaced the partial requirements tariff pursuant to which GEORGIA previously sold wholesale energy to MEAG. Since 1977, Dalton has filled its requirements from generation facilities acquired from GEORGIA and through partial requirements purchases. One municipally-owned electric distribution system's full requirements are served under a market-based contract by GEORGIA. (See Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein.)

GULF and MISSISSIPPI provide wholesale requirements for one municipal system each.

GEORGIA has entered into substantially similar agreements with Georgia Transmission Corporation (formerly OPC's transmission division), MEAG and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of each. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. (See Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein.)

SCS, acting on behalf of ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH, also has a contract with SEPA providing for the use of those companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain United States government hydroelectric projects.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the 1973 State Territorial Electric Service Act. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein on March 29, 1973 (451 municipalities, including Atlanta, Columbus, Macon, Augusta, Athens, Rome and Valdosta, to GEORGIA; 115 to electric cooperatives; and 50 to publicly-owned systems). Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in the Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, the Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 kilowatts may receive electric service from the supplier of its choice. (See also Item 1 - BUSINESS - "Competition" herein.)

Under and subject to the provisions of its franchises and concessions and the 1973 State Territorial Electric Service Act, SAVANNAH has the full but nonexclusive right to serve the City of Savannah, the Towns of Bloomingdale, Pooler, Garden City, Guyton, Newington, Oliver, Port Wentworth, Rincon, Tybee Island, Springfield, Thunderbolt, Vernonburg, and in conjunction with a secondary supplier, the Town of Richmond Hill. In addition, SAVANNAH has been assigned certain unincorporated areas in Chatham, Effingham, Bryan, Bulloch and Screven Counties by the Georgia PSC. (See also Item 1 - BUSINESS - "Competition" herein.)

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to MISSISSIPPI and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by MISSISSIPPI, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 300,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Long-Term Power Sales and Lease Agreements

Reference is made to Note 5 to the financial statements for SOUTHERN; Note 6 to the financial statements for ALABAMA, GULF and MISSISSIPPI, and Note 7 to the financial statements for GEORGIA in Item 8 herein for information regarding contracts for the sales and lease of capacity and energy to non-territorial customers.

Competition

The electric utility industry in the United States is currently undergoing a period of dramatic change as a result of regulatory and competitive factors. Among the primary agents of change has been the Energy Act. The Energy Act allows IPPs to access a utility's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build cogeneration plants for a utility's large industrial and commercial customers, and sell energy generation to other utilities. Also, electricity sales for resale rates are being driven down by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers. The integrated Southeast utilities are aggressively working to maintain and expand their share of wholesale sales in the Southeastern power markets.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers 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, Florida, Georgia, and Mississippi, none have been enacted. Enactment 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 current energy crisis in California. As a result of this crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The inability of a company to recover its investments, including the regulatory assets described in Note 1 to each registrant's respective financial statements, could have a material adverse effect on such company's financial condition and results of operations. The integrated Southeast utilities are attempting to minimize or reduce their cost exposure. Reference is made to Note 3 to the financial statements for SOUTHERN under "Alabama Power Rate Adjustment Procedures" and "Georgia Power 1998 Retail Rate Order" for information regarding these efforts.

Reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" herein for information relating to an RTO filing with FERC.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. Conversely, if the integrated Southeast utilities do not remain low-cost producers and provide quality service, then energy sales growth could be limited, and this could significantly erode earnings. Reference is made to ALABAMA, GULF, MISSISSIPPI and SAVANNAH, "Management's Discussion and Analysis - Future Earnings Potential" in Item 7 herein for further discussion of competition.

To adapt to a less regulated, more competitive environment, SOUTHERN continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, acquisitions involving other utility or non-utility businesses or properties, internal restructuring, disposition of certain assets, or some combination thereof. Furthermore, SOUTHERN may engage in other new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations and financial condition of SOUTHERN. (See Item 1 - BUSINESS - "Other Business" herein.)

As a result of the foregoing factors, SOUTHERN has experienced increasing competition for available off-system sales of capacity and energy from neighboring utilities and alternative sources of energy. Additionally, the future effect of cogeneration and small-power production facilities on the SOUTHERN system cannot currently be determined but may be adverse.

ALABAMA currently has cogeneration contracts in effect with twelve industrial customers. Under the terms of these contracts, ALABAMA purchases excess generation of such companies. During 2000, ALABAMA purchased approximately 104.9 million kilowatt-hours from such companies at a cost of $3.1 million.

GEORGIA currently has contracts in effect with eight small power producers whereby GEORGIA purchases their excess generation. During 2000, GEORGIA purchased 11.6 million kilowatt-hours from such companies at a cost of $482,000. GEORGIA has purchased power agreements for electricity with two cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2000, GEORGIA purchased 698.3 million kilowatt-hours at a cost of $70.4 million from these facilities. Reference is made to Note 4 to the financial statements for GEORGIA in Item 8 herein for information regarding purchased power commitments.

GULF currently has agreements in effect with four industrial customers pursuant to which GULF purchases "as available" energy from customer-owned generation. During 2000, GULF purchased 127 million kilowatt-hours from such companies for $5.2 million.

SAVANNAH currently has cogeneration contracts in effect with five large customers. Under the terms of these contracts, SAVANNAH purchases excess generation of such companies. During 2000, SAVANNAH purchased 43.9 million kilowatt-hours from such companies at a cost of $2.7 million.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements and reliability. These factors are, in turn, affected by, among other influences, regulatory, political and environmental considerations, taxation and supply.

The integrated Southeast utilities have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees as the result of self-generation (as described above) and fuel switching by customers and other factors. (See also Item 1 - BUSINESS - "Territory Served by the Integrated Southeast Utilities" herein for information concerning suppliers of electricity operating within or near the areas served at retail by the integrated Southeast utilities.)

Regulation

State Commissions

The integrated Southeast utilities are subject to the jurisdiction of their respective state regulatory commissions, which have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC) and, in the cases of the Georgia PSC and Mississippi PSC, in part, retail service territories. (See Item 1 - BUSINESS - "Rate Matters" and "Territory Served by the Integrated Southeast Utilities" herein.)

Holding Company Act

SOUTHERN is registered as a holding company under the Holding Company Act, and it and its subsidiary companies are subject to the regulatory provisions of said Act, including provisions relating to the issuance of securities, sales and acquisitions of securities and utility assets, services performed by SCS and Southern Nuclear, and the activities of certain of SOUTHERN's special purpose subsidiaries.

While various proposals have been introduced in Congress regarding the Holding Company Act, the prospects for legislative reform or repeal are uncertain at this time.

Federal Power Act

The Federal Power Act subjects the integrated Southeast utilities and SEGCO to regulation by the FERC as companies engaged in the transmission or sale at wholesale of electric energy in interstate commerce, including regulation of accounting policies and practices.

ALABAMA and GEORGIA are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing ALABAMA generating stations having an aggregate installed capacity of 1,593,600 kilowatts and

18 existing GEORGIA generating stations having an aggregate installed capacity of 1,074,696 kilowatts.

GEORGIA has started the relicensing process for the Middle Chattahoochee Project. This project consists of the Goat Rock, Oliver, and North Highlands facilities.

GEORGIA and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 kilowatt capacity which began commercial operation in 1995. (See Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein and Note 3 to SOUTHERN's and GEORGIA's financial statements in Item 8 herein for additional information.)

Licenses for all projects, excluding those discussed above, expire in the period 2007-2033 in the case of ALABAMA's projects and in the period 2005-2036 in the case of GEORGIA's projects.

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. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property taken, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property taken.

Atomic Energy Act of 1954

ALABAMA, GEORGIA and Southern Nuclear are subject to the provisions of the Atomic Energy Act of 1954, as amended, which vests jurisdiction in the NRC over the construction and operation of nuclear reactors, particularly with regard to certain public health and safety and antitrust matters. The National Environmental Policy Act has been construed to expand the jurisdiction of the NRC to consider the environmental impact of a facility licensed under the Atomic Energy Act of 1954, as amended.

NRC operating licenses currently expire in June 2017 and March 2021 for Plant Farley units 1 and 2, respectively, in August 2014 and June 2018 for Plant Hatch units 1 and 2, respectively, and in January 2027 and February 2029 for Plant Vogtle units 1 and 2, respectively. On February 29, 2000, Southern Nuclear, on behalf of GEORGIA, filed a license renewal application with the NRC for Plant Hatch units 1 and 2. If approved, the operating license will be extended to 2034.

Reference is made to Notes 1 and 10 to SOUTHERN's, Notes 1 and 11 to ALABAMA's and Notes 1 and 5 to GEORGIA's financial statements in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance. Additionally, Note 3 to GEORGIA's financial statements contains information regarding nuclear performance standards imposed by the Georgia PSC that may impact retail rates.

Environmental Regulation

The integrated Southeast utilities' and SEGCO's operations are subject to federal, state and local environmental requirements which, among other things, control emissions of particulates, sulfur dioxide and nitrogen oxides into the air; the use, transportation, storage and disposal of hazardous and toxic waste; and discharges of pollutants, including thermal discharges, into waters of the United States. The integrated Southeast utilities and SEGCO expect to comply with such requirements, which generally are becoming increasingly stringent, through technical improvements, the use of appropriate combinations of low-sulfur fuel and chemicals, addition of environmental control facilities, changes in control techniques and reduction of the operating levels of generating facilities. Failure to comply with such requirements could result in the complete shutdown of individual facilities not in compliance as well as the imposition of civil and criminal penalties.

Reference is made to each registrant's "Management's Discussion and Analysis" in Item 7 herein for a discussion of the Clean Air Act and other environmental legislation and proceedings, including a pending lawsuit brought on behalf of the EPA.

The integrated Southeast utilities' and SEGCO's estimated capital expenditures for environmental quality control facilities for the years 2001, 2002 and 2003 are as follows: (in millions)

	2001	2002	2003
ALABAMA	$ 76	$144	$ 48
GEORGIA	345	302	48
GULF	7	7	14
MISSISSIPPI	2	4	-
SAVANNAH	2	1	4
SEGCO	1	1	1
Total	$433	$459	$115

The foregoing estimates are included in the current construction programs. (See Item 1 - BUSINESS - "Construction Programs" herein.)

Additionally, each integrated Southeast utility and SEGCO has incurred costs for environmental remediation of various sites. Reference is made to each registrant's "Management's Discussion and Analysis" in Item 7 herein for information regarding the registrants' environmental remediation efforts. Also, see Note 3 to SOUTHERN's and GEORGIA's financial statements in Item 8 herein for information regarding the identification of sites that may require environmental remediation by GEORGIA.

The integrated Southeast utilities and SEGCO are unable to predict at this time what additional steps they may be required to take as a result of the implementation of existing or future quality control requirements for air, water and hazardous or toxic materials, but such steps could adversely affect system operations and result in substantial additional costs.

The outcome of the matters mentioned above under "Regulation" cannot now be determined, except that these developments may result in delays in obtaining appropriate licenses for generating facilities, increased construction and operating costs, or reduced generation, the nature and extent of which, while not determinable at this time, could be substantial.

Rate Matters

Rate Structure

The rates and service regulations of the integrated Southeast utilities are uniform for each class of service throughout their respective service areas. Rates for residential electric service are generally of the block type based upon kilowatt-hours used and include minimum charges.

Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer including those with special features to encourage off-peak usage. Additionally, the integrated Southeast utilities are allowed by their respective PSCs to negotiate the terms and compensation of service to large customers. Such terms and compensation of service, however, are subject to final PSC approval. ALABAMA, GEORGIA and SAVANNAH are allowed by state law to recover fuel and net purchased energy costs through fuel cost recovery provisions which are adjusted to reflect increases or decreases in such costs. GULF recovers from retail customers costs of fuel, net purchased power, energy conservation and environmental compliance through provisions which are adjusted to reflect increases or decreases in such costs. GULF's recovery of these costs is based upon an annual projection - any over/under recovery during such period is reflected in a subsequent annual period with interest. With respect to MISSISSIPPI's retail rates, fuel and purchased power costs are billed to such customers under the fuel and energy adjustment clause. The adjustment factors for MISSISSIPPI's retail and wholesale rates are generally levelized based on the estimated energy cost for the year, adjusted for any actual over/under collection from the previous year. Revenues are adjusted for differences between recoverable fuel costs and amounts actually recovered in current rates.

Rate Proceedings

Reference is made to Note 3 to each registrant's financial statements in Item 8 herein for a discussion of rate matters. Reference is also made to GULF's

"Management's Discussion and Analysis – Future Earnings Potential" in Item 7 herein for a discussion of recent Florida PSC matters.

Integrated Resource Planning

GEORGIA and SAVANNAH filed a new Integrated Resource Plan with the Georgia PSC on January 31, 2001. The plans specify how GEORGIA and SAVANNAH each intends to meet the future electrical needs of their customers through a combination of demand-side and supply-side resources. The Georgia PSC must pre-certify these new resources. Once certified, all prudently incurred construction costs and purchased power costs will be recoverable through rates.

In July 1998, the Georgia PSC approved GEORGIA's and SAVANNAH's 1998 Integrated Resource Plans as filed, with minor modifications. The approved plans identify resource needs of approximately 800 megawatts to 1,200 megawatts starting in the summer of 2002. As a result, GEORGIA and SAVANNAH issued a joint request for proposals for their collective needs of 800 megawatts to 1,200 megawatts for 2002 and 2003. The bids were evaluated against self-build options, and a certification filing for the selected resources was approved by the Georgia PSC in March 2000. The selected resources for retail needs in Georgia are: (1) a 7-year purchased power agreement with the West Georgia Generating Company for 310 megawatts starting in 2002, increasing to 465 megawatts in 2005, and terminating at the end of 2009; and (2) a 7 ½-year purchased power agreement for two 568 megawatt combined cycle units to be located at Plant Wansley starting in 2002 and terminating at the end of 2009. SAVANNAH has a 7-year purchased power agreement with GEORGIA for 200 megawatts of the 1,136 megawatt addition at Plant Wansley starting in 2002 and terminating in 2009. After 2009, this capacity will be available to the wholesale market.

On December 15, 2000, GEORGIA filed a certification request for a 7-year purchased power agreement for 571 megawatts starting in 2003 and 610 megawatts starting in 2004 to be served from two combined cycle units at Plant Goat Rock; and 615 megawatts in 2004 to be served from a combined cycle unit at Plant Autaugaville. In addition, GEORGIA is seeking certification for upgrades from 3 megawatts to 9 megawatts at Plant Goat Rock Hydro units 1 and 2.

GEORGIA expects the Georgia PSC to approve the 2001 Integrated Resource Plan and grant certification of the purchased power agreements in July 2001.

Environmental Cost Recovery Plans

GULF and MISSISSIPPI both have retail rate mechanisms that provide for recovery of environmental compliance costs. For a description of these plans, see Note 3 to each of GULF's and MISSISSIPPI's financial statements in Item 8 herein.

Employee Relations

The companies of the SOUTHERN system had a total of 26,021 employees on their payrolls at December 31, 2000.

	Employees at December 31, 2000
ALABAMA	6,871
GEORGIA	8,855
GULF	1,327
MISSISSIPPI	1,319
SAVANNAH	554
SCS	3,431
Southern Nuclear	3,009
Other	655
Total	26,021

The integrated Southeast utilities have separate agreements with local unions of the IBEW generally covering wages, working conditions and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance and construction employees.

ALABAMA has agreements with the IBEW on a three-year contract extending to August 14, 2001. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

GEORGIA has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2002.

GULF has an agreement with the IBEW on a three-year contract extending to August 15, 2001.

MISSISSIPPI has an agreement with the IBEW on a four-year contract extending to August 16, 2002.

SAVANNAH has four-year labor agreements with the IBEW and the Office and Professional Employees International Union that expire April 15, 2003 and December 1, 2003, respectively.

Southern Nuclear has agreements with the IBEW on separate three-year contracts extending to August 15, 2001 for Plant Farley and to June 30, 2002 for Plants Hatch and Vogtle. Upon notice given at least 60 days prior to these dates, negotiations may be initiated with respect to agreement terms to be effective after such dates.

Southern Nuclear also has an agreement with the United Plant Guard Workers of America for security officers at Plant Hatch extending to September 30, 2001. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

The agreements also subject the terms of the pension plans for the companies discussed above to collective bargaining with the unions at five-year intervals.

Item 2. PROPERTIES

Electric Properties – The Integrated Southeast Utilities

The integrated Southeast utilities and SEGCO, at December 31, 2000, operated 34 hydroelectric generating stations, 33 fossil fuel generating stations, three nuclear generating stations and four combined cycle/cogeneration stations. The amounts of capacity owned by each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
Fossil Steam		
Gadsden	Gadsden, AL	120,000
Gorgas	Jasper, AL	1,221,250
Barry	Mobile, AL	1,525,000
Greene County	Demopolis, AL	300,000 (2)
Gaston Unit 5	Wilsonville, AL	880,000
Miller	Birmingham, AL	2,532,288 (3)
ALABAMA Total		6,578,538
Arkwright	Macon, GA	160,000
Atkinson	Atlanta, GA	180,000
Bowen	Cartersville, GA	3,160,000
Branch	Milledgeville, GA	1,539,700
Hammond	Rome, GA	800,000
McDonough	Atlanta, GA	490,000
McManus	Brunswick, GA	115,000
Mitchell	Albany, GA	170,000
Scherer	Macon, GA	750,924 (4)
Wansley	Carrollton, GA	925,550 (5)
Yates	Newnan, GA	1,250,000
GEORGIA Total		9,541,174
Crist	Pensacola, FL	1,045,000
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Daniel	Pascagoula, MS	500,000 (6)
Scherer Unit 3	Macon, GA	204,500 (4)
GULF Total		2,134,500
Eaton	Hattiesburg, MS	67,500
Sweatt	Meridian, MS	80,000
Watson	Gulfport, MS	1,012,000
Daniel	Pascagoula, MS	500,000 (6)
Greene County	Demopolis, AL	200,000 (2)
MISSISSIPPI Total		1,859,500
McIntosh	Effingham County, GA	163,117
Kraft	Port Wentworth, GA	281,136
Riverside	Savannah, GA	102,278
SAVANNAH Total		546,531
Gaston Units 1-4	Wilsonville, AL	
SEGCO Total		1,000,000 (7)
Total Fossil Steam		21,660,243
Nuclear Steam		
Farley	Dothan, AL	
ALABAMA Total		1,720,000
Hatch	Baxley, GA	899,612 (8)
Vogtle	Augusta, GA	1,060,240 (9)
GEORGIA Total		1,959,852
Total Nuclear Steam		3,679,852
Combustion Turbines		
Greene County	Demopolis, AL	
ALABAMA Total		720,000
Arkwright	Macon, GA	30,580
Atkinson	Atlanta, GA	78,720
Bowen	Cartersville, GA	39,400
Dahlberg	Athens, GA	640,000
Intercession City	Intercession City, FL	47,333 (10)
McDonough	Atlanta, GA	78,800
McIntosh Units 1,2,3,4,7,8	Effingham County, GA	480,000
McManus	Brunswick, GA	481,700
Mitchell	Albany, GA	118,200
Robins	Warner Robins, GA	160,000
Wilson	Augusta, GA	354,100
Wansley	Carrollton, GA	26,322 (5)
GEORGIA Total		2,535,155
Lansing Smith Unit A	Panama City, FL	39,400
Pea Ridge Units 1-3	Pea Ridge, FL	14,250
GULF Total		53,650
Chevron Cogenerating Station	Pascagoula, MS	147,292 (11)
Sweatt	Meridian, MS	39,400
Watson	Gulfport, MS	39,360
MISSISSIPPI Total		226,052

Generating Station	Location	Nameplate Capacity (Kilowatts)
Boulevard	Savannah, GA	59,100
Kraft	Port Wentworth, GA	22,000
McIntosh Units 5&6	Effingham County, GA	160,000
SAVANNAH Total		241,100
Gaston **(SEGCO)**	Wilsonville, AL	19,680 (7)
Total Combustion Turbines		3,795,637
Cogeneration		
Washington County	Washington County, AL	123,428
GE Plastics Project	Burkeville, AL	104,800
Theodore	Theodore, AL	236,418
ALABAMA Total		464,646
Combined Cycle		
Barry	Mobile, AL	
ALABAMA Total		535,212
Hydroelectric Facilities		
Weiss	Leesburg, AL	87,750
Henry	Ohatchee, AL	72,900
Logan Martin	Vincent, AL	128,250
Lay	Clanton, AL	177,000
Mitchell	Verbena, AL	170,000
Jordan	Wetumpka, AL	100,000
Bouldin	Wetumpka, AL	225,000
Harris	Wedowee, AL	135,000
Martin	Dadeville, AL	154,200
Yates	Tallassee, AL	32,000
Thurlow	Tallassee, AL	60,000
Lewis Smith	Jasper, AL	157,500
Bankhead	Holt, AL	54,000
Holt	Holt, AL	40,000
ALABAMA Total		1,593,600

Generating Station	Location	Nameplate Capacity
Barnett Shoals (Leased)	Athens, GA	2,800
Bartletts Ferry	Columbus, GA	173,000
Goat Rock	Columbus, GA	26,000
Lloyd Shoals	Jackson, GA	14,400
Morgan Falls	Atlanta, GA	16,800
North Highlands	Columbus, GA	29,600
Oliver Dam	Columbus, GA	60,000
Rocky Mountain	Rome, GA	215,256 (12)
Sinclair Dam	Milledgeville, GA	45,000
Tallulah Falls	Clayton, GA	72,000
Terrora	Clayton, GA	16,000
Tugalo	Clayton, GA	45,000
Wallace Dam	Eatonton, GA	321,300
Yonah	Toccoa, GA	22,500
6 Other Plants		18,080
GEORGIA Total		1,077,736
Total Hydroelectric Facilities		2,671,336
Total Generating Capacity		32,806,926

Notes:

(1) For additional information regarding facilities jointly-owned with non-affiliated parties, see Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein.

(2) Owned by ALABAMA and MISSISSIPPI as tenants in common in the proportions of 60% and 40%, respectively.

(3) Excludes the capacity owned by AEC.

(4) Capacity shown for GEORGIA is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for GULF is 25% of Unit 3.

(5) Capacity shown is GEORGIA's portion (53.5%) of total plant capacity.

(6) Represents 50% of the plant which is owned as tenants in common by GULF and MISSISSIPPI.

(7) SEGCO is jointly-owned by ALABAMA and GEORGIA. (See Item 1 - BUSINESS herein.)

(8) Capacity shown is GEORGIA's portion (50.1%) of total plant capacity.

(9) Capacity shown is GEORGIA's portion (45.7%) of total plant capacity.

(10) Capacity shown represents 33-1/3% of total plant capacity. GEORGIA owns a 1/3 interest in the unit with 100% use of the unit from June through September. FPC operates the unit.

(11) Generation is dedicated to a single industrial customer.

(12) Capacity shown is GEORGIA's portion (25.4%) of total plant capacity. OPC operates the plant.

Except as discussed below under "Titles to Property," the principal plants and other important units of the integrated Southeast utilities and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

MISSISSIPPI owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States is paying a use fee over a forty-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2000, the unamortized portion of this cost was $34.8 million.

The all-time maximum demand on the integrated Southeast utilities and SEGCO was 31,359,000 kilowatts and occurred in August 2000. This amount excludes demand served by capacity retained by MEAG and Dalton and excludes demand associated with power purchased from OPC and SEPA by its preference customers. The reserve margin for the integrated Southeast utilities and SEGCO at that time was 8.1%. For additional information on peak demands, reference is made to Item 6 - SELECTED FINANCIAL DATA herein.

ALABAMA and GEORGIA will incur significant costs in decommissioning their nuclear units at the end of their useful lives. (See Item 1 - BUSINESS - "Regulation - Atomic Energy Act of 1954" and Note 1 to SOUTHERN's, ALABAMA's and GEORGIA's financial statements in Item 8 herein.)

Jointly-Owned Facilities

ALABAMA and GEORGIA have sold and GEORGIA has purchased undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership resulting from these transactions are as follows:

	Total Capacity	Percentage Ownership						
		ALABAMA	AEC	GEORGIA	OPC	MEAG	DALTON	FPC
	(Megawatts)							
Plant Miller								
Units 1 and 2	1,320	91.8%	8.2%	-%	-%	-%	-%	-%
Plant Hatch	1,796	-	-	50.1	30.0	17.7	2.2	-
Plant Vogtle	2,320	-	-	45.7	30.0	22.7	1.6	-
Plant Scherer								
Units 1 and 2	1,636	-	-	8.4	60.0	30.2	1.4	-
Plant Wansley	1,779	-	-	53.5	30.0	15.1	1.4	-
Rocky Mountain	848	-	-	25.4	74.6	-	-	-
Intercession City, FL	142	-	-	33.3	-	-	-	66.7

ALABAMA and GEORGIA have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City, as described below) as agent for the joint owners.

In addition, GEORGIA has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by MEAG that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the 1987 and 1990 write-offs of Plant Vogtle costs, the cost of such capacity and energy is included in purchased power from non-affiliates in GEORGIA's Statements of Income in Item 8 herein.

Titles to Property

The integrated Southeast utilities' and SEGCO's interests in the principal plants (other than certain pollution control facilities, one small hydroelectric generating station leased by GEORGIA and the land on which five combustion turbine generators of MISSISSIPPI are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens of applicable mortgage indentures (except for SEGCO) and to excepted encumbrances as defined therein. The integrated Southeast utilities own the fee interests in certain of their principal plants as tenants in common. (See Item 2 - PROPERTIES - "Jointly-Owned Facilities" herein.) Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In substantially all of its coal reserve lands, SEGCO owns or will own the coal only, with adequate rights for the mining and removal thereof.

Item 3. LEGAL PROCEEDINGS

(1) **United States of America v. ALABAMA**
(United States District Court for the Northern District of Alabama)

Reference is made to Note 3 to ALABAMA's financial statements in Item 8 herein under the caption "Environmental Litigation."

(2) **United States of America v. GEORGIA and SAVANNAH**
(United States District Court for the Northern District of Georgia)

On March 27, 2001, the U.S. District Court granted the EPA's motion to amend its complaint to add the alleged violations at SAVANNAH's Plant Kraft and to add SAVANNAH as a defendant and denied the EPA's motion to add GULF and MISSISSIPPI as defendants due to lack of jurisdiction.

Reference is made to Note 3 to GEORGIA's financial statements in Item 8 herein under the caption "Environmental Litigation."

(3) **Cooper et al. v. GEORGIA, SOUTHERN, SCS and Energy Solutions**
(Superior Court of Fulton County, Georgia)

Reference is made to Note 3 to SOUTHERN's and GEORGIA's financial statements in Item 8 herein under the caption "Race Discrimination Litigation."

(4) GEORGIA has been designated as a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act with respect to a site in Brunswick, Georgia.

Reference is made to Note 3 to SOUTHERN's and GEORGIA's financial statements in Item 8 herein under the captions "Georgia Power Potentially Responsible Party Status" and "Other Environmental Contingencies," respectively.

(5) **In re: Mobile Energy Services Company, LLC; In re: Mobile Energy Services Holdings, Inc.**
(U.S. Bankruptcy Court for the Southern District of Alabama).

Reference is made to Note 3 to SOUTHERN's financial statements in Item 8 herein under the caption "Mobile Energy Services' Petition for Bankruptcy."

(6) **Gordon v. SOUTHERN et al.**
(United States District Court for the Southern District of California)

Reference is made to Note 3 to SOUTHERN''s financial statements in Item 8 herein under the caption "California Electricity Markets Litigation."

(7) **Pier 23 Restaurant v. SOUTHERN et al.**
(United States District Court for the Northern District of California)

Reference is made to Note 3 to SOUTHERN''s financial statements in Item 8 herein under the caption "California Electricity Markets Litigation."

See Item 1 - BUSINESS - "Construction Programs," "Fuel Supply," "Regulation - Federal Power Act" and "Rate Matters" as well as Note 3 to each registrant's financial statements in Item 8 herein for a description of certain other administrative and legal proceedings discussed therein.

Additionally, each of the integrated Southeast utilities, SCS, Southern Nuclear, Energy Solutions and Southern LINC are, in the normal course of business, engaged in litigation or administrative proceedings that include, but are not limited to, acquisition of property, injuries and damages claims, and complaints by present and former employees.

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

ALABAMA

ALABAMA held a special meeting of shareholders on December 14, 2000, for the purpose of amending its charter to provide to the holders of Preferred Stock the right to vote at all elections of directors of ALABAMA. The amendment was passed and the vote tabulation was as follows:

	Shares		
	For	Against	Abstain
Common Stock	5,608,955	0	0
Preferred Stock	1,505,832	462,101	127,473
Total	7,114,787	462,101	127,473

GEORGIA

By unanimous written consent effective December 14, 2000, GEORGIA's common shareholder authorized amending GEORGIA's charter to provide to the holders of Preferred Stock the right to vote at all elections of directors of GEORGIA. The vote tabulation was as follows:

	Shares		
	For	Against	Abstain
Common Stock	7,761,500	0	0

GULF

GULF held a special meeting of shareholders on December 14, 2000, for the purpose of amending its charter to provide to the holders of Preferred Stock the right to vote at all elections of directors of GULF. The amendment was passed and the vote tabulation was as follows:

	Shares		
	For	Against	Abstain
Common Stock	992,717	0	0
Preferred Stock	26,842	1,321	21
Total	1,019,559	1,321	21

MISSISSIPPI

MISSISSIPPI held a special meeting of shareholders on December 14, 2000, for the purpose of amending its charter to provide to the holders of Preferred Stock the right to vote at all elections of directors of MISSISSIPPI. The amendment was passed and the vote tabulation was as follows:

	Shares		
	For	Against	Abstain
Common Stock	1,121,000	0	0
Preferred Stock	196,119	10,363	11,762
Total	1,317,119	10,363	11,762

EXECUTIVE OFFICERS OF SOUTHERN

(Identification of executive officers of SOUTHERN is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2000.

A. W. Dahlberg
Chairman and Director
Age 60
Elected Director in 1985 and Chairman effective March 1995 through March 2001, and Chief Executive Officer effective March 1995 to March 2001. Also served as President from January 1994 to June 1999.

H. Allen Franklin
President, Chief Executive Officer and Director
Age 56
Elected Director in 1988 and Chief Executive Officer effective March 1, 2001. Previously served as President and Chief Operating Officer of SOUTHERN from June 1999 to March 2001; and as President and Chief Executive Officer of GEORGIA from January 1994 to June 1999.

Elmer B. Harris
Executive Vice President and Director
Age 61
Elected Director in 1989 and Executive Vice President in 1991. He also has served as President and Chief Executive Officer of ALABAMA since 1989.

David M. Ratcliffe
Executive Vice President
Age 52
Elected in 1999. He also has served as President and Chief Executive Officer of GEORGIA since June 1999. Previously served as Executive Vice President, Treasurer and Chief Financial Officer of GEORGIA from March 1998 to June 1999; and as Senior Vice President of SOUTHERN from March 1995 to March 1998.

Stephen A. Wakefield
Senior Vice President and General Counsel
Age 60
Elected in 1997. Previously, he was a partner at the law firm of Akin, Gump, Strauss, Hauer & Feld, LLP from July 1991 through August 1997.

Gale E. Klappa
Financial Vice President, Chief Financial Officer and Treasurer
Age 50
Elected effective March 1, 2001. Previously served as Chief Strategic Officer of SOUTHERN from October 1999 to March 2001; President of Mirant's North America Group and Senior Vice President of Mirant from December 1998 to October 1999; and as President and Chief Executive Officer of Western Power Distribution, a subsidiary of Mirant located in Bristol, England, from September 1995 to December 1998.

Charles D. McCrary
Vice President
Age 49
Elected in 1998; serves as Chief Production Officer for the SOUTHERN system. He also has served as Executive Vice President of GEORGIA since May 1998. Previously, he served as Executive Vice President of ALABAMA from 1994 through April 1998.

W. G. Hairston, III
Age 56
President and Chief Executive Officer of Southern Nuclear since 1993.

The officers of SOUTHERN were elected for a term running from the last annual meeting of the directors (May 24, 2000) for one year until the next annual meeting or until their successors are elected and have qualified, except for Mr. Franklin and Mr. Klappa, whose elections were effective on the date indicated.

EXECUTIVE OFFICERS OF ALABAMA

(Identification of executive officers of ALABAMA is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2000.

Elmer B. Harris
President, Chief Executive Officer and Director
Age 61
Elected in 1989. Served as President and Chief Executive Officer since 1989. Elected Executive Vice President of SOUTHERN in 1991. Served as a Director of SOUTHERN since 1989.

Michael D. Garrett
Executive Vice President
Age 51
Elected in 1998. Served as Executive Vice President of Customer Service since January 2000. Previously served as Executive Vice President of External Affairs from March 1998 to January 2000; and Senior Vice President of External Affairs from February 1994 to March 1998.

William B. Hutchins, III
Executive Vice President, Chief Financial Officer and Treasurer
Age 57
Elected in 1991. Served as Treasurer since 1998 in addition to Executive Vice President and Chief Financial Officer since 1991.

C. Alan Martin
Executive Vice President
Age 52
Elected in 1999. Served as Executive Vice President of External Affairs since January 2000. Previously served as Executive Vice President and Chief Marketing Officer for SOUTHERN from 1998 to 1999; and Vice President of Human Resources for SOUTHERN from May 1995 to March 1998.

Jerry L. Stewart
Senior Vice President
Age 51
Elected in 1999. Served as Senior Vice President of Fossil and Hydro Generation since 1999. Previously served as Vice President of SCS from 1992 to 1999.

The officers of ALABAMA were elected for a term running from the last annual meeting of the directors (April 28, 2000) for one year until the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA

(Identification of executive officers of GEORGIA is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2000.

David M. Ratcliffe
President, Chief Executive Officer and Director
Age 52
Elected as an Executive Officer in 1998 and as Director in 1999. Served as President and Chief Executive Officer since June 1999. Previously served as Executive Vice President, Treasurer and Chief Financial Officer of GEORGIA from 1998 to 1999; and as Senior Vice President of SOUTHERN from March 1995 to March 1998.

William C. Archer, III
Executive Vice President
Age 52
Elected in 1995. Served as Executive Vice President of External Affairs since 1995. Previously served as Senior Vice President of External Affairs from April 1995 to September 1995.

Thomas A. Fanning
Executive Vice President, Treasurer and Chief Financial Officer
Age 43
Elected in 1999. Previously served as Senior Vice President of SOUTHERN from June 1998 to June 1999; and Senior Vice President and Chief Information Officer for SOUTHERN from March 1995 to 1998.

Gene R. Hodges
Executive Vice President
Age 62
Elected in 1986. Served as Executive Vice President of Customer Operations, Power Delivery and Safety since 1992.

James K. Davis
Senior Vice President
Age 60
Elected in 1993. Served as Senior Vice President of Corporate Relations since 1993, with Employee Relations being added to his responsibilities in 2000.

Robert H. Haubein
Senior Vice President
Age 60
Elected in 1992. Served as Senior Vice President of Fossil/Hydro Power since 1994.

Leonard J. Haynes
Senior Vice President
Age 50
Elected in 1998. Served as Senior Vice President of Marketing since 1998. Previously served as Vice President of Retail Sales and Services from October 1995 to November 1998.

Fred D. Williams
Senior Vice President
Age 56
Elected in 1992. Served as Senior Vice President of Resource Policy and Planning since 1998. Previously served as Senior Vice President of Wholesale Power Marketing from 1995 to 1998.

The officers of GEORGIA were elected for a term running from the last annual meeting of the directors (May 17, 2000) for one year until the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GULF

(Identification of executive officers of GULF is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2000.

Travis J. Bowden
President, Chief Executive Officer and Director
Age 62
Elected in 1994. Served as President and Chief Executive Officer since 1994.

Francis M. Fisher, Jr.
Vice President
Age 52
Elected in 1989. Served as Vice President of Power Delivery and Customer Operations since 1996. Previously served as Vice President of Employee and External Relations from 1989 to 1996.

John E. Hodges, Jr.
Vice President
Age 57
Elected in 1989. Served as Vice President of Marketing and Employee/External Affairs since 1996. Previously served as Vice President of Customer Operations from 1989 to 1996.

Ronnie R. Labrato
Comptroller and Chief Financial Officer
Age 47
Elected as an Executive Officer in July 2000. Previously served as Controller from 1992 to 2000.

Robert G. Moore
Vice President
Age 51
Elected in 1997. Served as Vice President of Power Generation and Transmission of GULF and Vice President of Fossil Generation of SCS since 1997. Previously served as Plant Manager of Plant Bowen at GEORGIA from March 1993 to August 1997.

Warren E. Tate
Secretary/Treasurer and
Regional Chief Information Officer
Age 58
Elected as an Executive Officer in July 2000. Served as Secretary/Treasurer and Regional Chief Information Officer since 1996.

The officers of GULF were elected for a term running from the last annual meeting of the directors (July 28, 2000) for one year until the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF MISSISSIPPI

(Identification of executive officers of MISSISSIPPI is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2000.

Dwight H. Evans
President, Chief Executive Officer and Director
Age 52
Elected in 1995. Previously served as Executive Vice President of External Affairs of GEORGIA from 1989 to 1995.

H. E. Blakeslee
Vice President
Age 60
Elected in 1984. Served as Vice President of Customer Services and Retail Marketing since 1984.

Don E. Mason
Vice President
Age 59
Elected in 1983. Served as Vice President of External Affairs and Corporate Services since 1983.

Michael W. Southern
Vice President, Secretary, Treasurer and Chief Financial Officer
Age 48
Elected in 1995. Served as Vice President, Secretary, Treasurer and Chief Financial Officer since 1995.

Gene L. Ussery, Jr.
Vice President
Age 51
Elected in 2000. Served as Vice President of Power Generation and Delivery since September 2000. Previously served as Northern Cluster Manager at GEORGIA for Plants Hammond, Bowen and McDonough-Atkinson from July 2000 to September 2000. He served as Manager of Plant Bowen at GEORGIA from 1997 to 2000; and Manager of Plant McDonough at GEORGIA from 1996 to 1997.

The officers of MISSISSIPPI were elected for a term running from the last annual meeting of the directors (April 26, 2000) for one year until the next annual meeting or until their successors are elected and have qualified, except for Mr. Ussery, whose election was effective on September 21, 2000.

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Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

(a) The common stock of SOUTHERN is listed and traded on the New York Stock Exchange. The stock is also traded on regional exchanges across the United States. High and low stock prices, per the New York Stock Exchange Composite Tape during each quarter for the past two years were as follows:

	High	Low
2000		
First Quarter	$25-7/8	$20-3/8
Second Quarter	27-7/8	21-11/16
Third Quarter	35	23-13/32
Fourth Quarter	33-22/25	27-1/2
1999		
First Quarter	$29-5/8	$23-1/4
Second Quarter	29-3/16	22-3/4
Third Quarter	28	25
Fourth Quarter	27-1/8	22-1/16

There is no market for the other registrants' common stock, all of which is owned by SOUTHERN. On February 28, 2001, the closing price of SOUTHERN's common stock was $30.95.

(b) Number of SOUTHERN's common stockholders at December 31, 2000: 160,116

Each of the other registrants have one common stockholder, SOUTHERN.

(c) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by SOUTHERN and the integrated Southeast utilities to their stockholder(s) for the past two years were as follows: (in thousands)

Registrant	Quarter	2000	1999
SOUTHERN	First	$220,557	$233,879
	Second	217,289	233,445
	Third	217,289	228,690
	Fourth	218,098	225,470
ALABAMA	First	103,600	98,000
	Second	105,200	98,400
	Third	104,400	99,700
	Fourth	103,900	103,500
GEORGIA	First	136,500	133,100
	Second	138,600	133,700
	Third	137,600	135,500
	Fourth	136,900	140,700
GULF	First	14,600	15,000
	Second	14,900	15,100
	Third	14,800	15,300
	Fourth	14,700	15,900
MISSISSIPPI	First	13,600	13,800
	Second	13,800	13,800
	Third	13,700	14,000
	Fourth	13,600	14,500
SAVANNAH	First	6,100	6,200
	Second	6,200	6,200
	Third	6,000	6,300
	Fourth	6,000	6,500

The dividend paid per share by SOUTHERN was 33.5¢ for each quarter of 1999 and 2000. The dividend paid on SOUTHERN's common stock for the first quarter of 2001 was 33.5¢ per share.

The amount of dividends on their common stock that may be paid by the subsidiary registrants is restricted in accordance with their first mortgage bond indenture. The amounts of earnings retained in the business and the amounts restricted against the payment of cash dividends on common stock at December 31, 2000 were as follows:

	Retained Earnings	Restricted Amount
	(in millions)	
ALABAMA	$1,228	$ 796
GEORGIA	1,788	891
GULF	156	127
MISSISSIPPI	173	118
SAVANNAH	110	68
Consolidated	4,672	2,000

Item 6. SELECTED FINANCIAL DATA

SOUTHERN. Reference is made to information under the heading "Selected Consolidated Financial and Operating Data," contained herein at pages II-41 and II-42.

ALABAMA. Reference is made to information under the heading "Selected Financial and Operating Data," contained herein at pages II-74 and II-75.

GEORGIA. Reference is made to information under the heading "Selected Financial and Operating Data," contained herein at pages II-109 and II-110.

GULF. Reference is made to information under the heading "Selected Financial and Operating Data," contained herein at pages II-138 and II-139.

MISSISSIPPI. Reference is made to information under the heading "Selected Financial and Operating Data," contained herein at pages II-167 and II-168.

SAVANNAH. Reference is made to information under the heading "Selected Financial and Operating Data," contained herein at pages II-194 and II-195.

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

SOUTHERN. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-8 through II-17.

ALABAMA. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-46 through II-54.

GEORGIA. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-79 through II-87.

GULF. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-114 through II-122.

MISSISSIPPI. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-143 through II-150.

SAVANNAH. Reference is made to information under the heading "Management's Discussion and Analysis of Results of Operations and Financial Condition," contained herein at pages II-172 through II-178.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Reference is made to information in SOUTHERN's "Management's Discussion and Analysis - Market Price Risk" and to Note 1 to SOUTHERN's financial statements under the heading "Financial Instruments for Non-Trading Activities" contained herein on pages II-13 through II-14 and II-28, respectively.

Reference is also made to "Management's Discussion and Analysis – Exposure to Market Risks" in Item 7 of ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH contained herein at pages II-51, II-83. II-118, II-146, and II-175, respectively.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2000 FINANCIAL STATEMENTS

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

None.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

MANAGEMENT'S REPORT

The management of Southern Company has prepared -- and is responsible for -- the consolidated 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 audit committee of the board of directors, composed of five independent directors provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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 consolidated financial statements present fairly, in all material respects, the financial position, results of operations, and cash flows of Southern Company and its subsidiary companies in conformity with accounting principles generally accepted in the United States.

H. Allen Franklin
President and Chief Executive Officer

Gale E. Klappa
Financial Vice President, Chief Financial Officer, and Treasurer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Southern Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company (a Delaware corporation) and subsidiary companies as of December 31, 2000 and 1999, and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2000. 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 consolidated financial statements (pages II-18 through II-40) referred to above present fairly, in all material respects, the financial position of Southern Company and subsidiary companies as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Overview of Consolidated Earnings

Southern Company's solid financial performance resulted in record earnings for 2000. Higher earnings were driven by both strong growth of selling electricity in the Southeast and by the global subsidiary's competitive energy supply business outside the Southeast. Reported earnings in both 2000 and 1999 reflected significant items not related to the normal day-to-day business activities. After adjusting for these items, earnings per share for 2000 was $2.13 compared with $1.90 in 1999. Earnings as reported and the details of earnings as adjusted are shown in the following table.

In April 2000, Southern Company announced an initial public offering of up to 19.9 percent of Mirant Corporation -- formerly Southern Energy, Inc. -- and its intentions to spin off the remaining ownership of Mirant to Southern Company stockholders within 12 months of the initial stock offering. On October 2, 2000, Mirant completed an initial public offering of 66.7 million shares of common stock.

On February 19, 2001, Southern Company's board of directors approved the spin off of the remaining ownership of 272 million Mirant shares to be completed in a tax free distribution on April 2, 2001. As a result of the spin off, Southern Company financial statements and related information reflect Mirant as discontinued operations.

A reconciliation of reported consolidated earnings, including discontinued operations, to earnings as adjusted – which exclude non-day to day business items – and the related explanations are as follows:

	Consolidated Net Income 2000	Consolidated Net Income 1999	Earnings Per Share 2000	Earnings Per Share 1999
	(in millions)			
Earnings from –				
Continuing operations	$ 994	$ 915	$1.52	$1.33
Discontinued operations	319	361	.49	.53
Earnings as reported	1,313	1,276	2.01	1.86
Mirant transition costs	80	–	.12	–
Mobile Energy write down	10	69	.01	.10
Gain on asset sale	–	(78)	–	(.11)
Work force reductions	–	50	–	.07
Other	(8)	(14)	(.01)	(.02)
Total adjustments	82	27	.12	.04
Earnings as adjusted	$1,395	$1,303	$2.13	$1.90

Mirant's transition costs shown in the table include charges related to becoming a public company and changes in their tax strategy in Asia.

In 2000 and 1999, Southern Company recorded asset impairment charges related to Mobile Energy Services – see Note 3 to the financial statements. In 1999, Mirant sold a portion of its business in the United Kingdom. Work force reduction programs began in late 1999 for a German utility in which Mirant has an ownership interest.

Southern Company Business Activities

Discussion of the results of operations is focused on the traditional business of the integrated Southeast utilities. The remaining portion of Southern Company's other business activities include telecommunications, energy products and services, leveraged leasing activities, as well as the parent holding company. The impact of these other business activities on the consolidated results of operations is not significant. For more information, see Note 12.

Integrated Southeast Utilities

The five integrated Southeast utilities provide electric service in four states. These utilities are Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric. A condensed income statement for these companies is as follows:

	Amount 2000	Increase (Decrease) From Prior Year 2000	Increase (Decrease) From Prior Year 1999
		(in millions)	
Operating revenues	$9,860	$735	$(238)
Fuel	2,564	236	7
Purchased power	677	268	13
Other operation and maintenance	2,472	41	4
Depreciation and amortization	1,135	89	(277)
Taxes other than income taxes	532	11	13
Total operating expenses	7,380	645	(240)
Operating income	2,480	90	2
Other income, net	(18)	(11)	(84)
Earnings before interest and taxes	2,462	79	(82)
Interest expenses and other	650	15	(44)
Income taxes	703	28	(28)
Net income	$1,109	$ 36	$ (10)

Revenues

Operating revenues for the integrated Southeast utilities in 2000 and the amount of change from the prior year are as follows:

	Amount 2000	Increase (Decrease) From Prior Year 2000	1999
		(in millions)	
Retail --			
Base revenues	**$6,014**	**$174**	$(262)
Fuel cost recovery and other	**2,599**	**353**	76
Total retail	**8,613**	**527**	(186)
Sales for resale --			
Within service area	**377**	**27**	(24)
Outside service area	**600**	**127**	(49)
Total sales for resale	**977**	**154**	(73)
Other operating revenues	**270**	**54**	21
Operating revenues	**$9,860**	**$735**	$(238)
Percent change		**8.1%**	(2.5)%

Base revenues increased $174 million in 2000 as a result of continued customer growth in the traditional service area and the positive impact of weather on energy sales. However, total base revenues of $5.8 billion in 1999 declined as a result of a Georgia Power rate reduction and recorded revenue sharing in 1999. For additional information, see Note 3 to the financial statements under "Georgia Power 1998 Retail Rate Order." Customer growth in the Southeast somewhat offset the rate decrease.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses -- including the fuel component of purchased energy -- and do not affect net income. However, cash flow is affected by the economic loss from untimely recovery of these receivables. Each company has filed or will be filing for approval of new fuel rates to be more reflective of escalating fuel costs.

Revenues from sales for resale within the service area were up as a result of additional demand during the hot summer of 2000. Sales for resale revenues within the service area were $350 million in 1999, down 6.5 percent from the prior year. This sharp decline resulted primarily from supplying less electricity under contractual agreements with certain wholesale customers in 1999.

Energy sales for resale outside the service area are principally unit power sales under long-term contracts to Florida utilities. Economy energy and energy under short-term contracts are also sold for resale outside the service area. Revenues from long-term unit power 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. The capacity and energy components of the unit power contracts were as follows:

	2000	1999	1998
		(in millions)	
Capacity	**$177**	$174	$196
Energy	**178**	157	152
Total	**$355**	$331	$348

Capacity revenues in 2000 and 1999 varied slightly compared with the prior year as a result of adjustments and true-ups related to contractual pricing. No significant declines in the amount of capacity are scheduled until the termination of the contracts in 2010.

Energy Sales

The changes in revenues for the traditional business in the Southeast are influenced heavily by the amount of energy sold each year. Kilowatt-hour sales for 2000 and the percent change by year were as follows:

(billions of kilowatt-hours)	Amount 2000	Percent Change 2000	1999	1998
Residential	**46.2**	**6.5%**	(0.2)%	10.9%
Commercial	**46.2**	**6.6**	4.0	7.2
Industrial	**56.7**	**1.0**	1.6	2.1
Other	**1.0**	**2.7**	1.6	3.1
Total retail	**150.1**	**4.3**	1.7	6.2
Sales for resale --				
Within service area	**9.6**	**1.5**	(4.1)	(0.4)
Outside service area	**17.2**	**33.0**	(0.4)	(5.6)
Total	**176.9**	**6.4**	1.2	4.7

The rate of growth in 2000 total retail energy sales was very strong. Residential energy sales reflected a substantial increase as a result of the hotter-than-normal summer weather and the number of residential customers served increased by 59,000 during the year.

Commercial and industrial sales, both in 2000 and 1999, continued to show slight gains in excess of the national averages. This reflects the strength of business and economic conditions in Southern Company's traditional service area in the southeastern United States. The rate of increase in 1999 total retail energy sales was significantly lower than in 1998. Residential energy sales experienced a decline as a result of milder weather in 1999, which strongly affected the total retail sales increase of 1.7 percent. Energy sales to retail customers are projected to increase at an average annual rate of 2.1 percent during the period 2001 through 2011.

Sales to customers outside the service area under long-term contracts for unit power sales increased 21 percent in 2000 and increased 19 percent in 1999. These changes in sales were influenced by weather and fluctuations in prices for oil and natural gas, the primary fuel sources for utilities with which the company has long-term contracts. However, these fluctuations in energy sales under long-term contracts have minimal effects on earnings because the energy is generally sold at variable cost.

Expenses

In 2000, operating expenses of $7.4 billion increased $645 million compared with the prior year. The costs to produce electricity for the traditional business in 2000 increased by $498 million to meet higher energy demands. Non-production operation and maintenance expenses increased $47 million in 2000. In 2000, depreciation and amortization expenses increased $89 million of which $50 million resulted from the 1998 Georgia Power rate order as referred to earlier.

In 1999, operating expenses of $6.7 billion decreased $240 million. This decline was driven by a reduction of $277 million accelerated depreciation of plant being recorded primarily as a result of the 1998 Georgia Power rate order. The costs to produce electricity for the traditional business in the Southeast for 1999 increased by $68 million to meet higher energy demands. All other operation and maintenance expenses declined by $44 million.

Fuel costs constitute the single largest expense for the integrated Southeast utilities. 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 kilowatt-hour generated -- within the traditional business service area -- were as follows:

	2000	1999	1998
Total generation (billions of kilowatt-hours)	**174**	165	164
Sources of generation (percent) --			
Coal	**78**	78	77
Nuclear	**16**	17	16
Hydro	**2**	2	4
Oil and gas	**4**	3	3
Average cost of fuel per net kilowatt-hour generated (cents) --	**1.51**	1.45	1.48

In 2000, fuel and purchased power costs increased $504 million as a result of 10.6 billion more kilowatt-hours being sold than in 1999. Demand was met with some 2.5 billion additional kilowatt-hours being purchased and using generation with higher unit fuel cost than last year.

Total fuel and purchased power costs of $2.7 billion in 1999 increased only $20 million while total energy sales increased 2.0 billion kilowatt-hours compared with the amounts recorded in 1998. Continued efforts to control energy costs helped lower the average cost of fuel per net kilowatt-hour generated in 1999.

Total interest charges and other financing costs in 2000 increased $15 million reflecting new generating units being constructed requiring some external financing. Total interest charges and other financing costs in 1999 decreased $44 million from amounts reported in the previous year. The decline reflected additional refinancing of debt in 1999.

Discontinued Operations

Mirant is a global energy company whose businesses include competitive electricity distribution companies, independent power projects, and energy trading and risk management companies.

On February 19, 2001, Southern Company's board of directors approved the spin off of Mirant, to be effective on April 2, 2001. As a result of this action, Mirant's financial and related information is shown as discontinued operations. All historical financial statements, footnotes, and related disclosures have been reclassified to conform with the current year presentation.

Earnings from discontinued operations are shown net of income taxes and minority interest. Southern Company earnings per share as adjusted was $2.13 in 2000, of which Mirant's earnings as adjusted contributed approximately $0.60 per share. On the same basis in 1999, Southern Company earnings per share was $1.90, of which $0.47 was attributed to Mirant.

Effects of Inflation

Southern Company's traditional business of the integrated Southeast utilities is subject to rate regulation and income tax laws that are based on the recovery of 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 Southern 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.

Future Earnings Potential

The results of continuing operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors. The two major factors are the ability of the regulated integrated Southeast utilities to achieve energy sales growth while containing cost in a more competitive environment; and the profitability of the new competitive market-based wholesale generating facilities being added.

The traditional business or the five Southeast utilities currently operate as vertically integrated companies providing electricity to customers within the traditional service area of the southeastern United States. Prices for electricity provided to retail customers are set by state public service commissions under cost-based regulatory principles. Retail rates and earnings are reviewed and adjusted periodically within certain limitations based on earned return on equity. See Note 3 to the financial statements for additional information about these and other regulatory matters.

Future earnings for the traditional business in the near term will depend upon growth in energy sales, which 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 traditional service area.

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 cogeneration plants for a utility's large industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are affected by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers 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, Florida, Georgia, and Mississippi, none have been enacted. Enactment 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 current energy crisis in California. As a result of this crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The inability of a company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on financial condition and results of operations.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. Conversely, if Southern Company's integrated Southeast utilities do not remain low-cost producers and provide quality service, then energy sales growth could be limited, and this could significantly erode earnings.

To adapt to a less regulated, more competitive environment, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, acquisitions involving other utility or non-utility businesses or properties, internal restructuring, disposition of certain assets, or some combination thereof. Furthermore, Southern Company may engage in other new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations and financial condition of Southern Company.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. Southern Company filed on October 16, 2000, a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of Southern Company and any other participating utilities. Participants would have the option to either maintain their ownership, divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on Southern Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUHCA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUHCA. These entities are able to own and operate power generating facilities and sell power to affiliates -- under certain restrictions.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary -- Southern Power Company. The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. Southern Power will be the primary growth engine for Southern Company's market-based energy business. Energy from its assets will be marketed to wholesale customers under the Southern Company name. By 2005, plans call for Southern Power to have developed or acquired more than 7,500 megawatts dedicated to the competitive wholesale business. Within 10 years, the new wholesale generating company's goal is to own more than 15,000 megawatts.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, Southern Company recorded non-cash income of approximately $130 million in 2000. Pension plan income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan. For more information, see Note 2.

Southern 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."

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry -- including Southern Company's -- regarding the recognition, measurement, and classification in the financial statements of decommissioning costs for nuclear generating facilities. In response to these questions, the Financial Accounting Standards Board (FASB) is reviewing the accounting for liabilities related to the retirement of long-lived assets, including nuclear decommissioning. If the FASB issues new accounting rules, the estimated costs of retiring Southern Company's nuclear and other facilities may be required to be recorded as liabilities in the Consolidated Balance Sheets. Also, the annual provisions for such costs could change. Because of the company's current ability to recover asset retirement costs through rates, these changes would not have a significant adverse effect on results of operations. See Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning" for additional information.

The integrated Southeast utilities are 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 a company's operations 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 Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Southern Company utilizes financial instruments to reduce its exposure to changes in interest rates and foreign currency exchange rates. Southern Company also enters into commodity related forward contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales.

Substantially all of these bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

Southern Company adopted Statement No. 133 effective January 1, 2001. The cumulative effect of adoption was a reduction of approximately $300 million in comprehensive income, which was all related to discontinued operations. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from FASB is expected, which could additionally impact Southern Company's financial statements. Also, as wholesale energy markets mature, the accounting for future transactions could be significantly impacted by Statement No. 133, resulting in more volatility in net income and comprehensive income.

FINANCIAL CONDITION

Overview

Southern Company's financial condition continues to remain strong. In 2000, the integrated Southeast utilities' earnings were at the high end of their respective allowed range of return on equity. Also, earnings from discontinued operations made a solid contribution. These factors drove the reported consolidated net income to a record $1.31 billion in 2000. The quarterly dividend declared in January 2001 was 33 1/2 cents per share, or $1.34 annually. Southern Company is committed to a goal of maintaining its current annual dividend of $1.34 per share and to grow the dividend over time consistent with earnings expectations. After the Mirant spin off, Southern Company's target will be to grow earnings per share at an average annual rate of 3 to 5 percent.

Gross property additions to utility plant from continuing operations were $2.2 billion in 2000. The majority of funds needed for gross property additions since 1997 has been provided from operating activities. The Consolidated Statements of Cash Flows provide additional details.

Market Price Risk

Southern Company is exposed to market risks, including changes in interest rates, currency exchange 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. Generally, company policy is that derivatives are to be used only for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

The company's market risk exposures relative to interest rate changes have not changed materially versus the previous reporting period. In addition, the company is not aware of any facts or circumstances that would significantly impact such exposures in the near-term.

If the company sustained a 100 basis point change in interest rates for all variable rate debt, the change would affect annualized interest expense by approximately $23 million at December 31, 2000. Based on the company's overall interest rate exposure at December 31, 2000, including derivative and other interest rate sensitive instruments, a near-term 100 basis point change in interest rates would not materially affect the consolidated financial statements.

Due to cost-based rate regulations, the integrated Southeast utilities have 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 companies enter into fixed price contracts for the purchase and sale of electricity through the wholesale electricity market. Realized gains and losses are recognized in the income statement as incurred. At December 31, 2000, exposure from these activities was not material to the consolidated financial statements.

For additional information, see Note 1 to the financial statements under "Financial Instruments for Non-Trading Activities."

Capital Structure

During 2000, the integrated Southeast utilities sold, through public authorities, $79 million of pollution control revenue bonds. In addition, senior notes of $650 million were issued in 2000. The companies continued to reduce financing costs by retiring higher-cost securities. Retirements of bonds and senior notes, including maturities, totaled $298 million during 2000, $1.2 billion during 1999, and $1.7 billion during 1998. Retirements of preferred stock totaled $86 million during 1999 and $239 million during 1998.

In December 2000, Southern Company issued 28 million treasury shares of common stock through a public offering. The offering raised $800 million and was priced at $28.50 per share. The proceeds were used to reduce debt.

In April 1999, Southern Company announced the repurchase of up to 50 million shares of its common stock over a two-year period through open market or privately negotiated transactions. Under this program, 50 million shares were repurchased by February 2000 at an average price of $25.53. Funding for the program was provided from Southern Company's commercial paper program. At the close of 2000, the company's common stock market value was 33 1/4 per share, compared with book value of $15.69 per share. The market-to-book value ratio was 212 percent at the end of 2000, compared with 170 percent at year-end 1999, and 207 percent at year-end 1998.

Capital Requirements for Construction

The construction program of Southern Company is budgeted at $2.9 billion for 2001, $2.6 billion for 2002, and $1.7 billion for 2003. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant 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.

Southern Company has approximately 6,600 megawatts of new generating capacity scheduled to be placed in service by 2003. Approximately 4,400 megawatts of additional new capacity will be dedicated to the wholesale market and owned by Southern Power. Significant construction of transmission and distribution facilities and upgrading of generating plants will be continuing for the traditional business in the Southeast.

Other Capital Requirements

In addition to the funds needed for the construction program, approximately $1.4 billion will be required by the end of 2003 for present improvement fund requirements and maturities of long-term debt. Also, the subsidiaries will continue to retire higher-cost debt and preferred stock and replace these obligations with lower-cost capital if market conditions permit.

Environmental Matters

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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 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.

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) were signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected Southern Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995 and some 50 generating units were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions compliance totaled approximately $300 million.

Phase II sulfur dioxide compliance was required in 2000. Southern Company used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased total construction expenditures through 2000 by approximately $100 million.

The one-hour ozone non-attainment standards for the Atlanta and Birmingham areas have been set and must be implemented in May 2003. Seven generating plants will be affected in the Atlanta area and two plants in the Birmingham area. Additional construction expenditures for compliance with these new rules are currently estimated at approximately $935 million.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Alabama and Georgia. Additional construction expenditures for compliance with these new rules are currently estimated at approximately $195 million.

In December 2000, the EPA completed its utility studies for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls is expected to take place around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including: control strategies to reduce regional haze; limits on pollutant discharges to impaired waters; water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

Southern Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. Under these various laws and regulations, the subsidiaries could incur substantial costs to clean up properties. The subsidiaries conduct studies to determine the extent of any required cleanup costs and have recognized in their respective financial statements costs to clean up known sites. These costs for Southern Company amounted to $4 million in 2000, $4 million in 1999, and $6 million in 1998. Additional sites may require environmental remediation for which the subsidiaries may be liable for a portion or all required cleanup costs. See Note 3 to the financial statements for information regarding Georgia Power's potentially responsible party status at a site in Brunswick, Georgia.

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of Southern Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect Southern Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electromagnetic fields.

Sources of Capital

The amount and timing of additional equity capital to be raised in 2001 -- as well as in subsequent years -- will be contingent on Southern Company's investment opportunities. Equity capital can be provided from any combination of public offerings, private placements, or the company's stock plans.

The integrated Southeast utilities plan 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.

Southern Power will use both external funds and equity capital from Southern Company to finance its construction program.

To meet short-term cash needs and contingencies, Southern Company had at the beginning of 2001 approximately $199 million of cash and cash equivalents and $5.1 billion of unused credit arrangements with banks.

Cautionary Statement Regarding Forward-Looking Information

Southern Company's 2000 Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning the strategic goals for Southern Company's new wholesale business and also Southern Company's earnings per share and earnings growth goals. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of these terms or other comparable terminology. Southern 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 Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action against Georgia Power and potentially other of Southern Company's subsidiaries and the race discrimination litigation against certain of Southern Company's subsidiaries; the extent and timing of the entry of additional competition in the markets of Southern Company's subsidiaries; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by Southern Company; state and federal rate regulation in the United States and in foreign countries in which Southern Company's subsidiaries operate; political, legal and economic conditions and developments in the United States and in foreign countries in which Southern Company's subsidiaries operate; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the performance of projects undertaken by the non-traditional business and the success of efforts to invest in and develop new opportunities; the timing and acceptance of Southern Company's new product and service offerings; the ability of Southern Company to obtain additional generating capacity at competitive prices; developments in the California power markets, including, but not limited to, governmental intervention, deterioration in the financial condition of counterparties, default on receivables due, adverse results in current or future litigation and adverse changes in the tariffs of the California Power Exchange Corporation or the California Independent System Operator Corporation; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by Southern Company with the SEC.

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CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2000, 1999, and 1998
Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	1998
		(in millions)	
Operating Revenues:			
Retail sales	**$ 8,613**	$8,086	$8,272
Sales for resale	**977**	823	896
Other revenues	**476**	408	331
Total operating revenues	**10,066**	9,317	9,499
Operating Expenses:			
Fuel	**2,564**	2,328	2,321
Purchased power	**677**	409	396
Other operations	**1,862**	1,839	1,852
Maintenance	**852**	829	800
Depreciation and amortization	**1,171**	1,139	1,340
Taxes other than income taxes	**536**	523	511
Total operating expenses	**7,662**	7,067	7,220
Operating Income	**2,404**	2,250	2,279
Other Income:			
Interest income	**51**	70	154
Other, net	**(26)**	(55)	(53)
Earnings From Continuing Operations Before Interest and Income Taxes	**2,429**	2,265	2,380
Interest and Other:			
Interest expense, net	**659**	556	558
Distributions on capital and preferred securities of subsidiaries	**169**	175	141
Preferred dividends of subsidiaries	**19**	20	25
Total interest and other	**847**	751	724
Earnings From Continuing Operations Before Income Taxes	**1,582**	1,514	1,656
Income taxes	**588**	599	670
Earnings From Continuing Operations	**994**	915	986
Earnings from discontinued operations, net of income taxes of $86, $127, and $(121) for 2000, 1999, and 1998, respectively	**319**	361	(9)
Consolidated Net Income	**$ 1,313**	$1,276	$ 977
Common Stock Data:			
Basic and diluted earnings per share of common stock –			
Earnings per share from continuing operations	**$1.52**	$1.33	$ 1.41
Earnings per share from discontinued operations (Note 11)	**0.49**	0.53	(0.01)
Consolidated Basic and Diluted Earnings Per Share	**$2.01**	$1.86	$1.40
Average number of shares of common stock outstanding (in millions)	**653**	685	697
Cash dividends paid per share of common stock	**$1.34**	$1.34	$1.34

The accompanying notes are an integral part of these statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	1998
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 1,313**	$ 1,276	$ 977
Adjustments to reconcile consolidated net income to net cash provided from operating activities --			
Less income from discontinued operations (Note 11)	**319**	361	(9)
Depreciation and amortization	**1,337**	1,216	1,530
Deferred income taxes and investment tax credits	**97**	10	21
Gain on asset sales	**5**	(2)	(20)
Other, net	**455**	888	(40)
Changes in certain current assets and liabilities --			
Receivables, net	**(379)**	(141)	(49)
Fossil fuel stock	**78**	(41)	(24)
Materials and supplies	**(15)**	(37)	10
Accounts payable	**180**	(65)	103
Other	**66**	244	(200)
Net cash provided from operating activities of continuing operations	**2,818**	2,987	2,317
Investing Activities:			
Gross property additions	**(2,225)**	(1,881)	(1,356)
Sales of property	**-**	-	83
Other	**(81)**	(400)	(166)
Net cash used for investing activities of continuing operations	**(2,306)**	(2,281)	(1,439)
Financing Activities:			
Increase (decrease) in notes payable, net	**(275)**	831	(365)
Proceeds --			
Other long-term debt	**743**	1,469	2,496
Capital and preferred securities	**-**	250	435
Preferred stock	**-**	-	200
Common stock	**910**	24	234
Redemptions --			
First mortgage bonds	**(211)**	(890)	(1,479)
Other long-term debt	**(204)**	(483)	(278)
Capital and preferred securities	**-**	(100)	-
Preferred stock	**-**	(86)	(239)
Common stock repurchased	**(415)**	(862)	(125)
Payment of common stock dividends	**(873)**	(921)	(933)
Other	**(54)**	(76)	(155)
Net cash provided from (used for) financing activities of continuing operations	**(379)**	(844)	(209)
Cash used for discontinued operations	**(88)**	(20)	(534)
Net Increase (Decrease) in Cash and Cash Equivalents	**45**	(158)	135
Cash and Cash Equivalents at Beginning of Year	**154**	312	177
Cash and Cash Equivalents at End of Year	**$ 199**	$ 154	$ 312
Supplemental Cash Flow Information From Continuing Operations:			
Cash paid during the year for --			
Interest (net of amount capitalized)	**$802**	$684	$680
Income taxes	**$661**	$656	$757

The accompanying notes are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2000 and 1999

Southern Company and Subsidiary Companies 2000 Annual Report

Assets	2000	1999
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 199**	$ 154
Special deposits	**6**	22
Receivables, less accumulated provisions for uncollectible accounts of $22 in 2000 and $22 in 1999	**1,312**	1,043
Unrecovered retail fuel clause revenue	**418**	244
Fossil fuel stock, at average cost	**195**	274
Materials and supplies, at average cost	**508**	493
Other	**187**	132
Total current assets	**2,825**	2,362
Property, Plant, and Equipment:		
In service	**34,188**	32,702
Less accumulated depreciation	**14,350**	13,655
	19,838	19,047
Nuclear fuel, at amortized cost	**215**	227
Construction work in progress	**1,569**	1,265
Total property, plant, and equipment	**21,622**	20,539
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**690**	658
Net assets of discontinued operations (Note 11)	**3,320**	2,913
Leveraged leases	**596**	556
Other	**165**	156
Total other property and investments	**4,771**	4,283
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**957**	987
Prepaid pension costs	**498**	368
Debt expense, being amortized	**99**	104
Premium on reacquired debt, being amortized	**280**	302
Other	**310**	346
Total deferred charges and other assets	**2,144**	2,107
Total Assets	**$31,362**	$29,291

The accompanying notes are an integral part of these balance sheets.

CONSOLIDATED BALANCE SHEETS (continued)
At December 31, 2000 and 1999
Southern Company and Subsidiary Companies 2000 Annual Report

Liabilities and Stockholders' Equity	2000	1999
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 67	$ 329
Notes payable	1,680	1,955
Accounts payable	869	669
Customer deposits	140	128
Taxes accrued --		
Income taxes	88	107
Other	208	198
Interest accrued	121	139
Vacation pay accrued	119	113
Other	445	391
Total current liabilities	3,737	4,029
Long-term debt (See accompanying statements)	7,843	7,251
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	4,074	3,884
Deferred credits related to income taxes	551	640
Accumulated deferred investment tax credits	664	693
Employee benefits provisions	478	465
Prepaid capacity revenues	58	80
Other	653	430
Total deferred credits and other liabilities	6,478	6,192
Company or subsidiary obligated mandatorily redeemable capital and preferred securities (See accompanying statements)	2,246	2,246
Cumulative preferred stock of subsidiaries (See accompanying statements)	368	369
Common stockholders' equity (See accompanying statements)	10,690	9,204
Total Liabilities and Stockholders' Equity	$31,362	$29,291
Commitments and Contingent Matters (Notes 1, 2, 3, 5, 8, 9, and 10)		

The accompanying notes are an integral part of these balance sheets.

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Southern Company and Subsidiary Companies 2000 Annual Report

		2000	1999	2000	1999
		(in millions)		(percent of total)	
Long-Term Debt of Subsidiaries:					
First mortgage bonds --					
Maturity	Interest Rates				
2000	6.00%	**$ -**	$ 200		
2003	6.13% to 6.63%	**325**	325		
2004	6.60%	**35**	35		
2005	6.07%	**10**	10		
2006 through 2010	6.50% to 6.90%	**95**	95		
2021 through 2025	6.88% to 9.00%	**635**	646		
2026 through 2030	6.88%	**30**	30		
Total first mortgage bonds		**1,130**	1,341		
Long-term notes payable --					
5.35% to 9.75% due 2001-2004		**766**	584		
5.38% to 8.58% due 2005-2008		**744**	964		
6.25% to 7.63% due 2009-2017		**170**	170		
6.38% to 8.12% due 2018-2038		**793**	801		
6.63% to 7.13% due 2039-2048		**1,029**	1,029		
Adjustable rates (5.79% to 7.75% at 1/1/01) due 2000-2005		**734**	148		
Total long-term notes payable		**4,236**	3,696		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
4.38% to 6.75% due 2000-2026		**539**	617		
Variable rates (4.73% to 5.05% at 1/1/01) due 2015-2025		**90**	120		
Non-collateralized:					
4.53% to 6.75% due 2015-2034		**406**	263		
Variable rates (3.50% to 5.35% at 1/1/01) due 2011-2037		**1,475**	1,510		
Total other long-term debt		**2,510**	2,510		
Capitalized lease obligations		**95**	97		
Unamortized debt (discount), net		**(61)**	(64)		
Total long-term debt (annual interest requirement -- $509 million)		**7,910**	7,580		
Less amount due within one year		**67**	329		
Long-term debt excluding amount due within one year		**7,843**	7,251	**37.1%**	38.0%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)

At December 31, 2000 and 1999

Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	2000	1999
	(in millions)		(percent of total)	
Company or Subsidiary Obligated Mandatorily Redeemable Capital and Preferred Securities:				
$25 liquidation value --				
6.85% to 7.00%	**435**	435		
7.13% to 7.38%	**297**	297		
7.60% to 7.63%	**415**	415		
7.75%	**649**	649		
8.14% to 8.19%	**400**	400		
Auction rate (6.52% at 1/1/01)	**50**	50		
Total company or subsidiary obligated mandatorily redeemable capital and preferred securities (annual distribution requirement -- $169 million)	**2,246**	2,246	**10.6**	11.8
Cumulative Preferred Stock of Subsidiaries:				
$100 par or stated value --				
4.20% to 7.00%	**98**	99		
$25 par or stated value --				
5.20% to 5.83%	**200**	200		
Adjustable and auction rates -- at 1/1/01:				
5.14% to 5.25%	**70**	70		
Total cumulative preferred stock of subsidiaries (annual dividend requirement -- $19 million)	**368**	369	**1.7**	1.9
Common Stockholders' Equity:				
Common stock, par value $5 per share --				
Authorized -- 1 billion shares				
Issued -- 2000: 701 million shares				
-- 1999: 701 million shares				
Treasury -- 2000: 19 million shares				
-- 1999: 35 million shares				
Par value	**3,503**	3,503		
Paid-in capital	**3,153**	2,480		
Treasury, at cost	**(545)**	(919)		
Retained earnings	**4,672**	4,232		
Accumulated other comprehensive income from discontinued operations	**(93)**	(92)		
Total common stockholders' equity	**10,690**	9,204	**50.6**	48.3
Total Capitalization	**$21,147**	$19,070	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

For the Years Ended December 31, 2000, 1999, and 1998
Southern Company and Subsidiary Companies 2000 Annual Report

	Common Stock				Accumulated Other Comprehensive Income From	
	Par Value	Paid In Capital	Treasury	Retained Earnings	Discontinued Operations	Total
			(in millions)			
Balance at January 1, 1998	$3,467	$2,331	$ -	$3,842	$ 7	$ 9,647
Net income	-	-	-	977	-	977
Other comprehensive income	-	-	-	-	8	8
Stock issued	32	132	70	-	-	234
Stock repurchased, at cost	-	-	(125)	-	-	(125)
Cash dividends	-	-	-	(933)	-	(933)
Other	-	-	(3)	(8)	-	(11)
Balance at December 31, 1998	3,499	2,463	(58)	3,878	15	9,797
Net income	-	-	-	1,276	-	1,276
Other comprehensive income	-	-	-	-	(107)	(107)
Stock issued	4	17	1	-	-	22
Stock repurchased, at cost	-	-	(861)	-	-	(861)
Cash dividends	-	-	-	(921)	-	(921)
Other	-	-	(1)	(1)	-	(2)
Balance at December 31, 1999	**3,503**	**2,480**	**(919)**	**4,232**	**(92)**	**9,204**
Net income	-	-	-	**1,313**	-	**1,313**
Other comprehensive income	-	-	-	-	**(1)**	**(1)**
Stock issued	-	-	**910**	-	-	**910**
Stock repurchased, at cost	-	-	**(414)**	-	-	**(414)**
Cash dividends	-	-	-	**(873)**	-	**(873)**
Other	-	**673**	**(122)**	-	-	**551**
Balance at December 31, 2000	**$3,503**	**$3,153**	**$(545)**	**$4,672**	**$ (93)**	**$10,690**

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2000, 1999, and 1998
Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	1998
		(in millions)	
Consolidated Net Income	**$1,313**	$1,276	$977
Other comprehensive income from discontinued operations, net of minority interest:			
Foreign currency translation adjustments	**(2)**	(165)	12
Less applicable income taxes (benefits)	**(1)**	(58)	4
Consolidated Comprehensive Income	**$1,312**	$1,169	$985

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Company is the parent company of five integrated Southeast utilities, a system service company, Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Southern Nuclear Operating Company (Southern Nuclear), Mirant Corporation -- formerly Southern Energy, Inc. -- and other direct and indirect subsidiaries. The integrated Southeast utilities -- Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four states. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). The system service company provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the integrated Southeast utilities and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States. As a result of the approved spin off of Mirant, Southern Company's financial statements and related information, both current and historical, reflect Mirant as discontinued operations. For additional information, see Note 11.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. All material intercompany items have been eliminated in consolidation. Certain prior years' data presented in the consolidated financial statements have been reclassified to conform with the current year presentation.

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both the company and its subsidiaries are subject to the regulatory provisions of the PUHCA. The integrated Southeast utilities also are subject to regulation by the FERC and their respective state public service commissions. The companies follow accounting principles generally accepted in the United States and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires the use of estimates, and the actual results may differ from those estimates.

Regulatory Assets and Liabilities

The integrated Southeast utilities are 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 Consolidated Balance Sheets at December 31 relate to the following:

	2000	1999
	(in millions)	
Deferred income tax charges	**$ 957**	$ 987
Premium on reacquired debt	**280**	302
Department of Energy assessments	**46**	52
Vacation pay	**92**	87
Postretirement benefits	**30**	33
Deferred income tax credits	**(551)**	(640)
Accelerated amortization	**(220)**	(85)
Storm damage reserves	**(34)**	(29)
Other, net	**116**	144
Total	**$ 716**	$ 851

In the event that a portion of a 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 value.

Revenues and Fuel Costs

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 integrated Southeast utilities include provisions to adjust billings for fluctuations in fuel costs, 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 rates.

Southern 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 continued 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 $136 million in 2000, $137 million in 1999, and $133 million in 1998. Alabama Power and Georgia Power have contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in January 1998 as required by the contracts, and the companies are pursuing legal remedies against the government for breach of contract. Effective June 2000, an on-site dry storage facility for Plant Hatch became operational. Sufficient capacity is believed to be available to continue dry storage operations at Plant Hatch through the life of the plant. Sufficient fuel storage capacity currently is available at Plant Vogtle to maintain full-core discharge capability for both units into the year 2014. 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 as early as 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. Alabama Power and Georgia Power -- based on its ownership interests -- estimate their respective remaining liability at December 31, 2000, under this law to be approximately $25 million and $19 million. These obligations are recorded in the Consolidated Balance Sheets.

Depreciation and Nuclear Decommissioning

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.4 percent in both 2000 and 1999 and 3.3 percent in 1998. 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 costs of decommissioning nuclear facilities and removal of other facilities.

Georgia Power recorded accelerated amortization and depreciation amounting to $135 million in 2000, $85 million in 1999, and $314 million in 1998. See Note 3 under "Georgia Power 1998 Retail Rate Order" for additional information.

The Nuclear Regulatory Commission (NRC) requires all licensees operating commercial power reactors to establish a plan for providing, with reasonable assurance, funds for decommissioning. Alabama Power and Georgia Power have 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 respective state public service commissions. 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. Alabama Power and Georgia Power have 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 a specific facility as of the site study year, and ultimate cost is the estimate to decommission a specific facility as of its retirement date. The estimated costs of decommissioning -- both site study costs and ultimate costs -- based on the most current study as of

December 31, 2000, for Alabama Power's Plant Farley and Georgia Power's ownership interests in plants Hatch and Vogtle were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle
Site study basis (year)	1998	2000	2000
Decommissioning periods:			
Beginning year	2017	2014	2027
Completion year	2031	2042	2045
		(in millions)	
Site study costs:			
Radiated structures	$629	$486	$420
Non-radiated structures	60	37	48
Total	$689	$523	$468
		(in millions)	
Ultimate costs:			
Radiated structures	$1,868	$1,004	$1,468
Non-radiated structures	178	79	166
Total	$2,046	$1,083	$1,634
Significant assumptions:			
Inflation rate	4.5%	4.7%	4.7%
Trust earning rate	7.0	6.5	6.5

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 these estimates.

Georgia Power has filed with the NRC an application requesting a 20-year renewal of the licenses for both units at Plant Hatch, which would permit the operation of both units until 2034.

Annual provisions for nuclear decommissioning are based on an annuity method as approved by the respective state public service commissions. The amount expensed in 2000 and fund balances were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle
		(in millions)	
Amount expensed in 2000	**$ 18**	**$ 19**	**$ 9**
Accumulated provisions:			
External trust funds, at fair value	$314	$230	$146
Internal reserves	38	20	12
Total	$352	$250	$158

Alabama Power's decommissioning costs for ratemaking are based on the site study. Effective January 1, 1999, the Georgia Public Service Commission (GPSC) increased Georgia Power's annual provision for decommissioning expenses to $28 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 1997. The estimates are $526 million and $438 million for plants Hatch and Vogtle, respectively. The ultimate costs associated with the 1997 NRC minimum funding requirements are $1.1 billion and $1.3 billion for plants Hatch and Vogtle, respectively. Alabama Power and Georgia Power expect their respective state public service commissions to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

Income Taxes

Southern 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.

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 funds used during construction was $71 million in 2000, $36 million in 1999, and $19 million in 1998. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property -- exclusive of minor items of property -- is capitalized.

Leveraged Leases

Southern Company has several leveraged lease agreements -- ranging up to 30 years -- that primarily relate to energy generation, distribution, and transportation assets. The investment income earned from these leveraged leases is immaterial for all periods presented.

Impairment of Long-Lived Assets and Intangibles

Southern 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 an estimate of undiscounted future cash flows attributable to the assets, as compared to 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 consolidated 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 costs 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.

Comprehensive Income

Comprehensive income -- consisting of net income and foreign currency translation adjustments, net of taxes -- is presented in the consolidated financial statements. The objective of the statement 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.

Financial Instruments for Non-Trading Activities

Southern Company uses derivative financial instruments to hedge exposures to fluctuations in interest rates, foreign currency exchange rates, and certain commodity prices. Gains and losses on qualifying hedges are deferred and recognized either in income or as an adjustment to the carrying amount of the hedged item when the transaction occurs.

Southern 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. The company is unaware of any counterparties that will fail to meet their obligations.

Southern Company has firm purchase commitments for equipment that require payment in euros. As a hedge against fluctuations in the exchange rate for euros, the company entered into forward currency swaps. The notional amount is 32 million euros maturing in 2001 through 2002. At December 31, 2000, the unrecognized gain on these swaps was approximately $3 million.

Other Southern 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, 2000	**$7,815**	**$7,702**
At December 31, 1999	7,483	7,046
Capital and preferred securities:		
At December 31, 2000	**2,246**	**2,190**
At December 31, 1999	2,246	1,942

The fair values for long-term debt and capital and preferred securities were based on either closing market price or closing price of comparable instruments.

2. RETIREMENT BENEFITS

Southern Company has defined benefit, trusteed, pension plans that cover substantially all employees. Southern Company provides certain medical care and life insurance benefits for retired employees. Substantially all these employees may become eligible for such benefits when they retire. The integrated Southeast utilities fund trusts to the extent required by their respective regulatory commissions. In late 2000, Southern Company adopted several pension and postretirement benefits plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits costs by approximately $28 million and $26 million, respectively.

The measurement date for plan assets and obligations is September 30 for each year. The following disclosures exclude discontinued operations.

Pension Plans

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

	Projected Benefit Obligations	
	2000	1999
	(in millions)	
Balance at beginning of year	**$3,098**	$3,084
Service cost	**94**	95
Interest cost	**227**	204
Benefits paid	**(145)**	(143)
Actuarial (gain) loss	**(28)**	(142)
Balance at end of year	**$3,246**	$3,098

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$5,266**	$4,646
Actual return on plan assets	**1,030**	771
Benefits paid	**(139)**	(151)
Balance at end of year	**$6,157**	$5,266

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

	2000	1999
	(in millions)	
Funded status	**$ 2,911**	$ 2,168
Unrecognized transition obligation	**(64)**	(77)
Unrecognized prior service cost	**97**	106
Unrecognized net gain	**(2,446)**	(1,829)
Prepaid asset recognized in the Consolidated Balance Sheets	**$ 498**	$ 368

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

	2000	1999	1998
		(in millions)	
Service cost	**$ 94**	$ 95	$ 86
Interest cost	**227**	204	204
Expected return on plan assets	**(384)**	(348)	(320)
Recognized net gain	**(64)**	(41)	(47)
Net amortization	**(3)**	(4)	(3)
Net pension cost (income)	**$(130)**	$ (94)	$ (80)

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	
	2000	1999
	(in millions)	
Balance at beginning of year	**$ 980**	$1,029
Service cost	**18**	21
Interest cost	**76**	68
Benefits paid	**(43)**	(36)
Actuarial (gain) loss	**21**	(102)
Balance at end of year	**$1,052**	$ 980

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$395**	$336
Actual return on plan assets	**47**	36
Employer contributions	**59**	60
Benefits paid	**(42)**	(37)
Balance at end of year	**$459**	$395

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

	2000	1999
	(in millions)	
Funded status	**$(593)**	$(585)
Unrecognized transition obligation	**189**	203
Unrecognized prior service cost	**66**	–
Unrecognized net loss (gain)	**(53)**	10
Fourth quarter contributions	**35**	26
Accrued liability recognized in the Consolidated Balance Sheets	**$(356)**	$(346)

Components of the postretirement plans' net periodic cost were as follows:

	2000	1999	1998
		(in millions)	
Service cost	**$ 18**	$ 21	$ 18
Interest cost	**76**	68	68
Expected return on plan assets	**(34)**	(26)	(21)
Recognized net gain	**–**	2	2
Net amortization	**18**	15	15
Net postretirement cost	**$ 78**	$ 80	$ 82

The weighted average rates assumed in the actuarial calculations for both the pension plans and postretirement benefits were:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00**	5.00
Long-term return on plan assets	**8.50**	8.50

An additional assumption used in measuring the accumulated postretirement benefit obligation was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005, 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	**$71**	**$63**
Service and interest costs	**6**	**6**

Employee Savings Plan

Southern 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 2000, 1999, and 1998 were $49 million, $46 million, and $43 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

Georgia Power Potentially Responsible Party Status

In January 1995, Georgia Power and four other unrelated entities were notified by the Environmental Protection Agency (EPA) that they have been designated as potentially responsible parties under the Comprehensive Environmental Response, Compensation, and Liability Act with respect to a site in Brunswick, Georgia. As of December 31, 2000, Georgia Power had recorded approximately $5 million in cumulative expenses associated with Georgia Power's agreed-upon share of the removal and remedial investigation and feasibility study costs for this site.

The final outcome of this matter cannot now be determined. However, based on the nature and extent of Georgia Power's activities relating to the site, management believes that the company's portion of any remaining remediation costs should not be material to the financial statements.

Environmental Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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.

Mobile Energy Services' Petition for Bankruptcy

Mobile Energy Services Holdings (MESH), a subsidiary of Southern Company, is the owner and operator of a facility that generates electricity, produces steam, and processes black liquor as part of a pulp and paper complex in Mobile, Alabama. On January 14, 1999, MESH filed a petition for Chapter 11 bankruptcy relief in the U.S. Bankruptcy Court. This action was in response to Kimberly-Clark Tissue Company's (Kimberly-Clark) announcement in May 1998 of plans to close its pulp mill, effective September 1, 1999. The pulp mill had historically provided 50 percent of MESH's revenues.

As a result of settlement discussions with Kimberly-Clark and MESH's bondholders, Southern Company recorded in 1999 a $69 million after-tax write down of its investment in MESH. Southern Company recorded an additional $10 million after-tax write down in 2000. At December 31, 2000, MESH had total assets of $373 million and senior debt outstanding of $190 million of first mortgage bonds and $72 million related to tax-exempt bonds. In connection with the bond financings, Southern Company provided certain limited guarantees, in lieu of funding debt service and maintenance reserve accounts with cash. As of December 31, 2000, Southern Company had paid the full $41 million pursuant to the guarantees. Southern Company continues to have guarantees outstanding of certain potential environmental and other obligations of MESH that represent a maximum contingent liability of $19 million at December 31, 2000. Mirant has agreed to indemnify Southern Company for any future obligations incurred under such guarantees.

On August 4, 2000, MESH filed a proposed plan of reorganization with the bankruptcy court. The proposed plan of reorganization was again amended on February 21, 2001. Changes in circumstances since the filing of the amended plan may require further modifications of the plan. Southern Company expects that approval of a plan of reorganization would result in a termination of Southern Company's ownership interest in MESH, but would not affect Southern Company's continuing guarantee obligations described earlier. The final outcome of this matter cannot now be determined.

California Electricity Markets Litigation

Five lawsuits have been filed in the superior courts of California alleging that certain owners of electric generation facilities in California, including Southern Company, engaged in various unlawful and anticompetitive acts that served to manipulate wholesale power markets and inflate wholesale electricity prices in California. Four of the suits seek class action status. One lawsuit naming Southern Company, Mirant, and other generators as defendants alleges that, as a result of the defendants' conduct, customers paid approximately $4 billion more for electricity than they otherwise would have and seeks an award of treble damages, as well as other injunctive and equitable relief. The other suits likewise seek treble damages and equitable relief. While two of the suits name Southern Company as a defendant, it appears that the allegations, as they may relate to Southern Company, are directed to activities of subsidiaries of Mirant. One such suit names Mirant itself as a defendant. Southern Company has notified Mirant of its claim for indemnification for costs associated with these actions under the terms of the master separation agreement that governs the spin off of Mirant. Mirant has undertaken the defense of all of the claims. The final outcome of these lawsuits cannot now be determined.

Race Discrimination Litigation

On July 28, 2000, a lawsuit alleging race discrimination was filed by three Georgia Power employees against Georgia Power, Southern Company, and the system service company in the United States District Court for the Northern District of Georgia. The lawsuit also raised claims on behalf of a purported class. The plaintiffs seek compensatory and punitive damages in an unspecified amount, as well as injunctive relief. On August 14, 2000, the lawsuit was amended to add four more plaintiffs and a new defendant, Southern Company Energy Solutions, Inc. The lawsuit is in the discovery phase. The final outcome of this matter cannot now be determined.

Alabama Power Rate Adjustment Procedures

In November 1982, the Alabama Public Service Commission (APSC) adopted rates that provide for periodic adjustments based upon Alabama Power's earned return on end-of-period retail common equity. The rates also provide for adjustments to recognize the placing of new generating facilities in retail service. Both increases and decreases have been placed into effect since the adoption of these rates. The rate adjustment procedures allow a return on common equity range of 13 percent to 14.5 percent and limit increases or decreases in rates to 4 percent in any calendar year. There is a moratorium on any periodic retail rate increases (but not decreases) until July 2001.

In December 1995, the APSC issued an order authorizing Alabama Power to reduce balance sheet items -- such as plant and deferred charges -- at any time the company's actual base rate revenues exceed the budgeted revenues. In April 1997, the APSC issued an additional order authorizing Alabama Power to reduce balance sheet asset items. This order authorizes the reduction of such items up to an amount equal to five times the total estimated annual revenue reduction resulting from future rate reductions initiated by Alabama Power. In 1998, Alabama Power -- in accordance with the 1995 rate order -- recorded $33 million of additional amortization of premium on reacquired debt. Alabama Power did not record any additional amounts in 2000 or 1999.

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

Georgia Power 1998 Retail Rate Order

As required by the GPSC, Georgia Power filed a general rate case in 1998. On December 18, 1998, the GPSC approved a three-year rate order for Georgia Power ending December 31, 2001. Under the terms of the order, Georgia Power's earnings will continue to be evaluated against a retail return on common equity range of 10 percent to 12.5 percent. Georgia Power's annual retail rates were decreased by $262 million effective January 1, 1999, and by an additional $24 million effective January 1, 2000. In addition, the order provided for $85 million annually to be applied to accelerated amortization or depreciation of assets, and up to an additional $50 million annually in 2000 and 2001 of any earnings above the 12.5 percent return. In accordance with the rate order, Georgia Power recorded accelerated amortization of $135 million and $85 million in 2000 and 1999, respectively. In May 2000, the GPSC ordered that these funds be maintained in a regulatory liability account and ordered that interest be accrued on this account at the prime rate. In 2000, interest of $10 million was recorded. These amounts are reflected on the balance sheets in deferred credits and other liabilities, other.

Two-thirds of any additional earnings above the 12.5 percent return in any year will be applied to rate reductions and the remaining one-third retained by Georgia Power. In both 2000 and 1999, Georgia Power's return was above 12.5 percent, and accordingly, it recorded in 1999 $79 million of revenues to be refunded to customers in 2000. In 2000, Georgia Power recorded $44 million as an estimate of revenues to be refunded in 2001. Georgia Power is required to file a general rate case on July 1, 2001. At that time, the GPSC is expected to determine whether the rate order should be continued, modified, or discontinued.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in units 1 and 2 of Plant Miller and related facilities jointly with Alabama Electric Cooperative, Inc.

Georgia Power owns undivided interests in plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia, the city of Dalton, Georgia, Florida Power & Light Company (FP&L), and Jacksonville Electric Authority (JEA). In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation (FPC) for a combustion turbine unit at Intercession City, Florida.

At December 31, 2000, Alabama Power's and Georgia Power's ownership and investment (exclusive of nuclear fuel) in jointly owned facilities with the above entities were as follows:

	Jointly Owned Facilities		
	Percent Ownership	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,301	$1,724
Plant Hatch (nuclear)	50.1	873	650
Plant Miller (coal) Units 1 and 2	91.8	743	312
Plant Scherer (coal) Units 1 and 2	8.4	112	53
Plant Wansley (coal)	53.5	300	150
Rocky Mountain (pumped storage)	25.4	169	72
Intercession City (combustion turbine)	33.3	11	1

Alabama Power and Georgia Power have contracted to operate and maintain the jointly owned facilities -- except for the Rocky Mountain project and Intercession City -- as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the Consolidated Statements of Income.

5. LONG-TERM POWER SALES AND LEASE AGREEMENTS

The integrated Southeast utilities have long-term contractual agreements for the sale and lease of capacity to certain non-affiliated utilities located outside the system's service area. These agreements are firm and are 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 specific generating plants is currently being sold to FP&L, FPC, and JEA. Under these agreements, approximately 1,500 megawatts of capacity is scheduled to be sold annually unless reduced by FP&L, FPC, and JEA for the periods after 2000 with a minimum of three years notice -- until the expiration of the contracts in 2010. Capacity revenues from unit power sales amounted to $177 million in 2000, $174 million in 1999, and $196 million in 1998.

During 2000, Georgia Power and Mississippi Power entered into certain operating leases for portions of their generating unit capacity. Capacity revenues from these operating leases amounted to $20 million in 2000 and are included in the financial statements as sales for resale. Minimum future capacity revenues from noncancelable operating leases as of December 31, 2000 are as follows:

Year	Amounts
	(in millions)
2001	$ 53
2002	66
2003	66
2004	66
2005	27
2006 and thereafter	114
Total	$392

6. INCOME TAXES

At December 31, 2000, the tax-related regulatory assets and liabilities were $957 million and $551 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. The following tables and disclosures exclude discontinued operations.

Details of income tax provisions are as follows:

	2000	1999	1998
		(in millions)	
Total provision for income taxes:			
Federal --			
Current	**$ 421**	$ 504	$ 548
Deferred	**95**	11	23
	516	515	571
State --			
Current	**71**	85	102
Deferred	**1**	(1)	(3)
	72	84	99
Total	**$ 588**	$ 599	$ 670

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:

	2000	1999
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$3,199**	$3,088
Property basis differences	**1,105**	1,175
Other	**650**	444
Total	**4,954**	4,707
Deferred tax assets:		
Federal effect of state deferred taxes	**111**	113
Other property basis differences	**206**	221
Deferred costs	**190**	102
Pension and other benefits	**125**	121
Other	**231**	198
Total	**863**	755
Net deferred tax liabilities	**4,091**	3,952
Portion included in current assets, net	**(17)**	(68)
Accumulated deferred income taxes in the Consolidated Balance Sheets	**$4,074**	$3,884

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 Consolidated Statements of Income. Credits amortized in this manner amounted to $30 million in 2000, $30 million in 1999, and $38 million in 1998. At December 31, 2000, all investment tax credits available to reduce federal income taxes payable had been utilized.

The provision for income taxes differs from the amount of income taxes determined by applying the applicable U.S. Federal statutory rate to earnings before income taxes and preferred dividends of subsidiaries, as a result of the following:

	2000	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.4**	3.8	3.8
Non-deductible book depreciation	**1.7**	1.9	4.0
Difference in prior years' deferred and current tax rate	**(1.3)**	(1.3)	(1.3)
Other	**(2.1)**	(0.3)	(1.6)
Effective income tax rate	**36.7%**	39.1%	39.9%

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.

7. COMMON STOCK

Stock Issued and Repurchased

The amount and timing of additional equity capital to be raised in 2001 -- as well as in subsequent years -- will be contingent on Southern Company's investment opportunities. Equity capital may be provided from any combination of public offerings, private placements, or the company's stock plans.

In December 2000, Southern Company issued 28 million treasury shares of common stock through a public offering. The offering, which included an overallotment of 3 million shares, raised some $800 million and was priced at $28.50 per share. The proceeds were used to repay short-term commercial paper.

In April 1999, Southern Company's Board of Directors approved the repurchase of up to 50 million shares of Southern Company's common stock over a two-year period through open market or privately negotiated transactions. Under this program, 50 million shares were repurchased by February 2000 at an average price of $25.53. Funding for the program was provided from Southern Company's commercial paper program.

Shares Reserved

At December 31, 2000, a total of 59 million shares was reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Performance Stock Plan.

Performance Stock Plan

The performance stock plan provides non-qualified stock options to a large segment of Southern Company's employees ranging from line management to executives. As of December 31, 2000, 5,744 current and former employees participated in the plan. The maximum number of shares of common stock that may be issued under the plan may not exceed 40 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the plan. Stock option activity in 1999 and 2000 for the plan is summarized below:

	Shares Subject To Option	Average Option Price Per Share
Balance at December 31, 1998	6,445,398	$22.77
Options granted	2,108,818	26.56
Options canceled	(28,630)	25.48
Options exercised	(56,708)	19.51
Balance at December 31, 1999	8,468,878	23.73
Options granted	6,977,038	23.25
Options canceled	(226,597)	23.66
Options exercised	(984,897)	21.63
Balance at December 31, 2000	**14,234,422**	**$23.63**
Shares reserved for future grants:		
At December 31, 1998	36,598,001	
At December 31, 1999	34,515,156	
At December 31, 2000	**27,750,261**	
Options exercisable:		
At December 31, 1999	4,525,349	
At December 31, 2000	**5,898,698**	

Southern Company accounts for its stock-based compensation plans in accordance with Accounting Principles Board Opinion No. 25. Accordingly, no compensation expense has been recognized.

The following table summarizes information about options outstanding at December 31, 2000:

	Price Range of Options		
	14-20	21-24	25-28
Outstanding:			
Shares (in thousands)	**430**	**10,217**	**3,587**
Average remaining life (in years)	**2.5**	**8.2**	**8.1**
Average exercise price	**$17.36**	**$22.79**	**$26.77**
Exerciseable:			
Shares (in thousands)	**424**	**3,653**	**1,822**
Average exercise price	**$17.64**	**$21.96**	**$26.84**

The estimated fair values of stock options granted in 2000, 1999 and 1998 were derived using the Black-Scholes stock option pricing model. The following table shows the assumptions and the weighted average fair values of stock options:

	2000	1999	1998
Interest rate	**6.7%**	5.8%	5.5%
Average expected life of stock options (in years)	**4.0**	3.7	3.7
Expected volatility of common stock	**20.9%**	20.7%	19.2%
Expected annual dividends on common stock	**$1.34**	$1.34	$1.34
Weighted average fair value of stock options granted	**3.36**	4.61	4.27

The pro forma impact on earnings of fair-value accounting for options granted -- as required by FASB Statement No. 123, Accounting for Stock-Based Compensation -- is 1.2 cents per share in 2000 and less than 1 cent in both 1999 and 1998.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to outstanding options under the Performance Stock Plan. The effect of the stock options was determined using the treasury stock method. Shares used to compute diluted earnings per share are as follows:

	Average Common Stock Shares		
	2000	1999	1998
	(in thousands)		
As reported shares	**653,086**	685,163	696,944
Effect of options	**1,108**	580	739
Diluted shares	**654,194**	685,743	697,683

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2000, consolidated retained earnings included $3.5 billion of undistributed retained earnings of the subsidiaries. Of this amount, $2.0 billion was restricted against the payment by the subsidiary companies of cash dividends on common stock under terms of bond indentures.

8. FINANCING

Capital and Preferred Securities

Company or subsidiary obligated mandatorily redeemable capital and preferred securities have been issued by special purpose financing entities of Southern Company and its subsidiaries. Substantially all the assets of these special financing entities are junior subordinated notes issued by the related company seeking financing. Each of these companies considers that the mechanisms and obligations relating to the capital or preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective special financing entities' payment obligations with respect to the capital or preferred securities. At December 31, 2000, capital securities of $950 million and preferred securities of $1.3 billion were outstanding. Southern Company guarantees the notes related to $950 million of capital or preferred securities issued on its behalf.

Long-Term Debt 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:

	2000	1999
	(in millions)	
Bond improvement fund requirements	**$11**	$ 14
Less:		
Portion to be satisfied by certifying property additions	**11**	9
Cash requirements	**-**	5
First mortgage bond maturities and redemptions	**-**	200
Other long-term debt maturities	**67**	124
Total	**$67**	$329

The first mortgage bond improvement fund requirements amount to 1 percent of each outstanding series of bonds authenticated under the indentures prior to January 1 of each year, other than those issued to collateralize pollution control revenue bonds and other obligations. The requirements may be satisfied by depositing cash or reacquiring bonds, or by pledging additional property equal to 166 2/3 percent of such requirements.

With respect to the collateralized pollution control revenue bonds, the integrated Southeast utilities have authenticated and delivered to trustees a like principal amount of first mortgage bonds as security for obligations under installment sale or loan agreements. The principal and interest on the first mortgage bonds will be payable only in the event of default under the agreements.

Improvement fund requirements and/or serial maturities through 2005 applicable to other long-term debt are as follows: $67 million in 2001; $489 million in 2002; $479 million in 2003; $323 million in 2004; and $600 million in 2005.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. The subsidiary companies' mortgages, which secure the first mortgage bonds issued by the companies, constitute a direct first lien on substantially all of the companies' respective fixed property and franchises. There are no agreements or other arrangements among the subsidiary companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At the beginning of 2001, unused credit arrangements with banks totaled $5.1 billion, of which $3.2 billion expires during 2001, $1.0 billion during 2002, and $900 million during 2003 and 2004. The following table outlines the credit arrangements by company:

	Amount of Credit			
			Expires	
Company	Total	Unused	2001	2002 & beyond
	(in millions)			
Alabama Power	$ 925	$ 925	$ 535	$ 390
Georgia Power	1,765	1,765	1,265	500
Gulf Power	123	115	115	-
Mississippi Power	117	117	117	-
Savannah Electric	65	50	40	10
Southern Company	2,100	2,100	1,100	1,000
Other	60	51	51	-
Total	$5,155	$5,123	$3,223	$1,900

Approximately $2.9 billion of the credit facilities allows for term loans ranging from one to three years. Most of the agreements include stated borrowing rates but also allow for competitive bid loans.

All of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. These balances are not legally restricted from withdrawal. Of the total $5.1 billion in unused credit, $2.1 billion, $1.65 billion, and $780 million are syndicated credit arrangements of Southern Company, Georgia Power, and Alabama Power, respectively. These facilities also require the payment of agent fees.

A portion of the $5.1 billion unused credit with banks is allocated to provide liquidity support to the companies' variable rate pollution control bonds. The amount of variable rate pollution control bonds requiring liquidity support as of December 31, 2000, was $1.6 billion.

Southern Company, Alabama Power, and Georgia Power borrow through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the companies from time to time borrow under uncommitted lines of credit with banks.

9. COMMITMENTS

Construction Program

Southern Company is engaged in continuous construction programs, currently estimated to total $2.9 billion in 2001, $2.6 billion in 2002, and $1.7 billion in 2003. The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; acquisition of additional generating assets; 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, 2000, significant purchase commitments were outstanding in connection with the construction program. Southern Company has approximately 6,600 megawatts of additional generating capacity scheduled to be placed in service by 2003.

See Management's Discussion and Analysis under "Environmental Matters" for information on the impact of the Clean Air Act Amendments of 1990 and other environmental matters.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, Southern 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. Also, Southern Company has entered into various long-term commitments for the purchase of electricity. Total estimated long-term obligations at December 31, 2000, were as follows:

Year	Fuel	Purchased Power
	(in millions)	
2001	$ 2,481	$ 81
2002	1,897	97
2003	1,711	99
2004	1,328	95
2005	1,055	95
2006 and thereafter	3,764	693
Total commitments	$12,236	$1,160

Operating Leases

Southern Company has operating lease agreements with various terms and expiration dates. These expenses totaled $42 million, $35 million, and $26 million for 2000, 1999, and 1998, respectively. At December 31, 2000, estimated minimum rental commitments for noncancelable operating leases were as follows:

Year	Amounts
	(in millions)
2001	$ 57
2002	71
2003	71
2004	68
2005	64
2006 and thereafter	388
Total minimum payments	$719

Guarantees

Southern Company has made separate guarantees to certain counterparties regarding performance of contractual commitments by Mirant's trading and marketing subsidiaries. At December 31, 2000, the total notional amount of guarantees was $419 million and the estimated fair value of net contractual commitments outstanding was approximately $259 million. Based upon a statistical analysis of credit risk, Southern Company's potential exposure under these contractual commitments would not materially differ from the estimated fair value.

At December 31, 2000, Southern Company had guaranteed $11 million related to a Mirant purchase power agreement. The guarantee expires March 2001. Southern Company also has guaranteed certain of Mirant's foreign currency swap transactions. At December 31, 2000, notional amounts under these swaps were the differences between £44 million and $68 million and between DM370 million and $206 million; however, due to favorable exchange rates Southern Company had no exposure under these guarantees. The sterling and deutsche mark swaps expire in 2002 and 2003, respectively.

After the spin off, Mirant will pay Southern Company a monthly fee of 1 percent on the average aggregate maximum principal amount of all guarantees outstanding until they are replaced or expire. Southern Company's guarantees related to Mirant trading and marketing activities are limited to a maximum of $425 million, with any guarantees since October 2, 2000 expiring no later than October 2, 2001. Mirant must use reasonable efforts to release Southern Company from all such support arrangements and will indemnify Southern Company for any obligations incurred.

10. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988, Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The act provides funds up to $9.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $200 million by private insurance, with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. A 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 Alabama Power and Georgia Power -- based on its ownership and buyback interests -- is $176 million and $178 million, respectively, per incident, but not more than an aggregate of $20 million per company to be paid for each incident in any one year.

Alabama Power and Georgia Power are members 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, both companies have 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 costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can be insured against increased costs of replacement power in an amount up to $3.5 million per week – starting 12 weeks after the outage -- for one year and up to $2.8 million per week for the second and third years.

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 Alabama Power and Georgia Power under the three NEIL policies would be $17 million and $19 million, respectively.

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.

11. DISCONTINUED OPERATIONS

In April 2000, Southern Company announced an initial public offering of up to 19.9 percent of Mirant and its intentions to spin off the remaining ownership of Mirant to Southern Company stockholders within 12 months of the initial stock offering. On October 2, 2000, Mirant completed an initial public offering of 66.7 million shares of common stock priced at $22 per share. This represented 19.7 percent of the 338.7 million shares outstanding. As a result of the stock offering, Southern Company recorded a $560 million increase in paid-in capital with no gain or loss being recognized.

On February 19, 2001, Southern Company's board of directors approved the spin off of its remaining ownership of 272 million Mirant shares to be completed in a tax free distribution on April 2, 2001. Shares from the spin off will be distributed at a ratio of approximately 0.4 for every share of Southern Company common stock held at record date.

As a result of the spin off, Southern Company's December 31, 2000, financial statements have been prepared with Mirant's results of operations and cash flows shown as discontinued operations. All historical financial statements presented and footnotes have been reclassified to conform to this presentation, with the historical assets and liabilities of Mirant presented on the balance sheet as net assets of discontinued operations.

Summarized financial information for the discontinued operations is as follows at December 31:

	2000	1999	1998
		(in millions)	
Revenues	**$13,315**	$2,265	$1,819
Income taxes	**86**	127	(121)
Net income	**319**	361	(9)

	2000	1999
	(in millions)	
Current assets	**$ 9,057**	$ 1,254
Total assets	**22,377**	12,191
Current liabilities	**9,726**	3,169
Total liabilities	**17,585**	8,473
Minority and other interests	**1,472**	805
Net assets of discontinued operations	**3,320**	2,913

12. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segment is the five integrated Southeast utilities that provide electric service in four states. Net income and total assets for discontinued operations are included in the reconciling eliminations column. The all other category includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include telecommunications, energy products and services, and leasing and financing services. Intersegment revenues are not material. Financial data for business segments and products and services are as follows:

Business Segments

Year	Integrated Southeast Utilities	All Other	Reconciling Eliminations	Consolidated
	(in millions)			
2000				
Operating revenues	**$ 9,860**	**$ 246**	**$ (40)**	**$10,066**
Depreciation and amortization	**1,135**	**36**	**–**	**1,171**
Interest income	**43**	**9**	**(1)**	**51**
Interest expense	**631**	**197**	**–**	**828**
Income taxes	**703**	**(115)**	**–**	**588**
Segment net income (loss)	**1,109**	**(115)**	**319**	**1,313**
Total assets	**26,917**	**2,200**	**2,245**	**31,362**
Gross property additions	**2,199**	**26**	**–**	**2,225**

Year	Integrated Southeast Utilities	All Other	Reconciling Eliminations	Consolidated
	(in millions)			
1999				
Operating revenues	$ 9,125	$ 221	$ (29)	$ 9,317
Depreciation and amortization	1,046	93	–	1,139
Interest income	64	50	(44)	70
Interest expense	613	155	(37)	731
Income taxes	675	(76)	–	599
Segment net income (loss)	1,073	(154)	357	1,276
Total assets	25,336	2,127	1,828	29,291
Gross property additions	1,854	27	–	1,881

Year	Integrated Southeast Utilities	All Other	Reconciling Eliminations	Consolidated
	(in millions)			
1998				
Operating revenues	$ 9,363	$ 167	$ (31)	$ 9,499
Depreciation and amortization	1,323	17	–	1,340
Interest income	150	58	(54)	154
Interest expense	654	99	(54)	699
Income taxes	703	(33)	–	670
Segment net income (loss)	1,083	(97)	(9)	977
Total assets	24,420	2,817	1,486	28,723
Gross property additions	1,298	58	–	1,356

Products and Services

Year	Integrated Southeast Utilities Revenues			
	Retail	Wholesale	Other	Total
	(in millions)			
2000	**$8,613**	**$977**	**$270**	**$9,860**
1999	8,086	823	216	9,125
1998	8,272	896	195	9,363

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2000 and 1999 -- including discontinued operations for net income and earnings per share -- are as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income	Per Common Share: Earnings	Per Common Share: Dividends	Price Range: High	Price Range: Low
	(in millions)						
March 2000	**$2,052**	**$ 428**	**$245**	**$0.38**	**$0.335**	**25 7/8**	**20 3/8**
June 2000	**2,522**	**598**	**342**	**0.52**	**0.335**	**27 7/8**	**21 11/16**
September 2000	**3,198**	**1,041**	**614**	**0.95**	**0.335**	**35**	**23 13/32**
December 2000	**2,294**	**337**	**112**	**0.16**	**0.335**	**33 22/25**	**27 1/2**
March 1999	$1,920	$ 408	$224	$0.32	$0.335	29 5/8	23 1/4
June 1999	2,288	569	314	0.45	0.335	29 3/16	22 3/4
September 1999	3,050	981	615	0.90	0.335	28	25
December 1999	2,059	292	123	0.19	0.335	27 1/8	22 1/16

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

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 1996-2000

Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in millions)	**$10,066**	$9,317	$9,499	$8,774	$8,675
Total Assets (in millions)	**$31,362**	$29,291	$28,723	$27,898	$26,352
Gross Property Additions (in millions)	**$2,225**	$1,881	$1,356	$1,138	$1,064
Return on Average Common Equity (percent)	**13.20**	13.43	10.04	10.30	12.53
Cash Dividends Paid Per Share of Common Stock	**$1.34**	$1.34	$1.34	$1.30	$1.26
Consolidated Net Income (in millions):					
Continuing operations	**$ 994**	$ 915	$986	$990	$1,046
Discontinued operations	**319**	361	(9)	(18)	81
Total	**$1,313**	$1,276	$977	$972	$1,127
Basic and Diluted Earnings Per Share of Common Stock:					
Continuing operations	**$1.52**	$1.33	$ 1.41	$ 1.45	$1.56
Discontinued operations	**0.49**	0.53	(0.01)	(0.03)	0.12
Total	**$2.01**	$1.86	$ 1.40	$1.42	$1.68
Capitalization (in millions):					
Common stock equity	**$10,690**	$ 9,204	$ 9,797	$ 9,647	$ 9,216
Preferred stock and securities	**2,614**	2,615	2,465	2,155	1,402
Long-term debt	**7,843**	7,251	6,505	6,347	6,556
Total excluding amounts due within one year	**$21,147**	$19,070	$18,767	$18,149	$17,174
Capitalization Ratios (percent):					
Common stock equity	**50.6**	48.3	52.2	53.2	53.7
Preferred stock and securities	**12.3**	13.7	13.1	11.9	8.2
Long-term debt	**37.1**	38.0	34.7	34.9	38.1
Total excluding amounts due within one year	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share (year-end)	**$15.69**	$13.82	$14.04	$13.91	$13.61
Market price per share:					
High	**35**	29 5/8	31 9/16	26 1/4	25 7/8
Low	**20 3/8**	22 1/16	23 15/16	19 7/8	21 1/8
Close	**33 1/4**	23 1/2	29 1/16	25 7/8	22 5/8
Market-to-book ratio (year-end) (percent)	**211.9**	170.0	207.0	186.0	166.2
Price-earnings ratio (year-end) (times)	**16.5**	12.6	20.8	18.2	13.5
Dividends paid (in millions)	**$873**	$921	$933	$889	$846
Dividend yield (year-end) (percent)	**4.0**	5.7	4.6	5.0	5.6
Dividend payout ratio (percent)	**66.5**	72.2	95.6	91.5	75.1
Shares outstanding (in thousands):					
Average	**653,087**	685,163	696,944	685,033	672,590
Year-end	**681,158**	665,796	697,747	693,423	677,036
Stockholders of record (year-end)	**160,116**	174,179	187,053	200,508	215,246
Customers (year-end) (in thousands):					
Residential	**3,398**	3,339	3,277	3,220	3,157
Commercial	**527**	513	497	479	464
Industrial	**14**	15	15	16	17
Other	**5**	4	5	5	5
Total	**3,944**	3,871	3,794	3,720	3,643
Employees (year-end)	**26,021**	26,269	25,206	24,682	25,034

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Southern Company and Subsidiary Companies 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in millions):					
Residential	**$ 3,367**	$3,105	$3,163	$2,837	$2,894
Commercial	**2,922**	2,743	2,763	2,595	2,559
Industrial	**2,292**	2,237	2,267	2,139	2,136
Other	**32**	1	79	76	76
Total retail	**8,613**	8,086	8,272	7,647	7,665
Sales for resale within service area	**377**	350	374	376	409
Sales for resale outside service area	**600**	473	522	510	429
Total revenues from sales of electricity	**9,590**	8,909	9,168	8,533	8,503
Other revenues	**476**	408	331	241	172
Total	**$10,066**	$9,317	$9,499	$8,774	$8,675
Kilowatt-Hour Sales (in millions):					
Residential	**46,213**	43,402	43,503	39,217	40,117
Commercial	**46,249**	43,387	41,737	38,926	37,993
Industrial	**56,746**	56,210	55,331	54,196	52,798
Other	**970**	945	929	903	911
Total retail	**150,178**	143,944	141,500	133,242	131,819
Sales for resale within service area	**9,579**	9,440	9,847	9,884	10,935
Sales for resale outside service area	**17,190**	12,929	12,988	13,761	10,777
Total	**176,947**	166,313	164,335	156,887	153,531
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.29**	7.15	7.27	7.23	7.21
Commercial	**6.32**	6.32	6.62	6.67	6.74
Industrial	**4.04**	3.98	4.10	3.95	4.04
Total retail	**5.74**	5.62	5.85	5.74	5.81
Sales for resale	**3.65**	3.68	3.92	3.75	3.86
Total sales	**5.42**	5.36	5.58	5.44	5.54
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,702**	13,107	13,379	12,296	12,824
Average Annual Revenue Per Residential Customer	**$998.38**	$937.81	$972.89	$889.50	$925.12
Plant Nameplate Capacity Owned (year-end) (megawatts)	**32,807**	31,425	31,161	31,146	31,076
Maximum Peak-Hour Demand (megawatts):					
Winter	**26,370**	25,203	21,108	22,969	22,631
Summer	**31,359**	30,578	28,934	27,334	27,190
System Reserve Margin (at peak) (percent)	**8.1**	8.5	12.8	15.0	14.0
Annual Load Factor (percent)	**60.2**	59.2	60.0	59.4	62.3
Plant Availability (percent):					
Fossil-steam	**86.8**	83.3	85.2	88.2	86.4
Nuclear	**90.5**	89.9	87.8	88.8	89.7
Source of Energy Supply (percent):					
Coal	**72.3**	73.1	72.8	74.7	73.3
Nuclear	**15.1**	15.7	15.4	16.5	16.7
Hydro	**1.5**	2.3	3.9	4.3	4.1
Oil and gas	**4.0**	2.8	3.3	1.7	1.5
Purchased power	**7.1**	6.1	4.6	2.8	4.4
Total	**100.0**	100.0	100.0	100.0	100.0

ALABAMA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT
Alabama Power Company 2000 Annual Report

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 audit committee of the board of directors, composed of independent directors, provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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.

Elmer B. Harris
Elmer B. Harris
President
and Chief Executive Officer

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

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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, 2000 and 1999, 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, 2000. 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 II-55 through II-73) referred to above present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Birmingham, Alabama
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Alabama Power Company's 2000 net income after dividends on preferred stock was $420 million, representing a $20 million (5 percent) increase from the prior year. This improvement is primarily attributable to an increase in territorial sales partially offset by increased non-fuel operating expenses.

In 1999, earnings were $400 million, representing a 6 percent increase from the prior year. This increase was due to a decrease in amortization related to premiums paid to reacquire debt pursuant to an Alabama Public Service Commission (APSC) order. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional details.

The return on average common equity for 2000 was 13.58 percent compared to 13.85 percent in 1999, and 13.63 percent in 1998.

Revenues

Operating revenues for 2000 were $3.7 billion, reflecting an increase from 1999. The following table summarizes the principal factors that have affected operating revenues for the past two years:

	Amount	Increase (Decrease) From Prior Year	
	2000	**2000**	1999
		(in thousands)	
Retail --			
Base revenues	**$2,108,939**	$ 80,264	$ 10,022
Fuel cost recovery and other	**843,768**	61,326	20,418
Total retail	**2,952,707**	141,590	30,440
Sales for resale --			
Non affiliates	**461,730**	46,353	(33,596)
Affiliates	**166,219**	73,780	(11,123)
Total sales for resale	**627,949**	120,133	(44,719)
Other operating revenues	**86,805**	20,264	13,380
Total operating revenues	**$3,667,461**	$281,987	$ (899)
Percent change		8.33%	(0.03)%

Retail revenues of $3.0 billion in 2000 increased $142 million (5 percent) from the prior year, compared with an increase of $30 million (1.1 percent) in 1999. The primary contributors to the increase in revenues in 2000 were the positive impact of weather on energy sales, continued economic growth in the Company's service territory, and an increase in fuel revenues. Fuel revenues have no effect on net income because they represent the recording of revenues to offset fuel expenses, including the fuel component of purchased energy. Fuel rates billed to customers are designed to fully recover fluctuating fuel costs over a period of time. Higher natural gas prices and decreased hydro production combined with increased costs of purchased power have resulted in a large under-recovery of fuel costs at December 31, 2000. Effective January 2001, the Company's fuel rate was increased to address this under-recovery. The Company expects to significantly reduce this balance over a three-year period.

The $20 million (30.5 percent) increase in other operating revenues in 2000 as compared to 1999 was due primarily to an increase in steam sales in conjunction with the operation of the Company's co-generation facilities.

Retail revenues in 1999 increased $30 million (1.1 percent) over 1998. The predominant factors causing the rise in revenues in 1999 were continued growth in the Company's service territory, as well as an increase in fuel revenues. These increases were offset by the effect of milder temperatures in 1999 as compared to 1998.

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 long-term power 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 were as follows:

	2000	1999	1998
		(in millions)	
Capacity	**$127**	$122	$142
Energy	**128**	112	118
Total	**$255**	$234	$260

Capacity revenues from non-affiliates were relatively unchanged in 2000 compared to the prior year. Capacity revenues from non-affiliates in 1999 decreased 13.9 percent compared to 1998. This decrease was attributable to the lowering of the equity return under formula rate contracts, as well as other adjustments and true-ups related to contractual pricing.

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.

Kilowatt-hour (KWH) sales for 2000 and the percent change by year were as follows:

	KWH	Percent Change	
	2000	2000	1999
	(millions)		
Residential	**16,772**	**6.8%**	(0.6)%
Commercial	**12,989**	**5.5**	3.4
Industrial	**22,101**	**0.7**	1.7
Other	**206**	**2.3**	2.3
Total retail	**52,068**	**3.8**	1.4
Sales for resale -			
Non-affiliates	**14,848**	**19.4**	5.0
Affiliates	**5,369**	**6.7**	(15.8)
Total	**72,285**	**6.9%**	0.5%

The increases in 2000 and 1999 retail energy sales were primarily due to the strength of business and economic conditions in the Company's service area. In 2000, residential energy sales experienced a 6.8 percent increase over the prior year primarily as a result of warmer summer temperatures and cold winter weather conditions compared to 1999. Assuming normal weather, sales to retail customers are projected to grow approximately 2.9 percent annually on average during 2001 through 2005.

Expenses

In 2000, total operating expenses of $2.7 billion 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, accompanied by a $23 million increase in maintenance expenses.

In 1999, total operating expenses of $2.5 billion decreased $13 million or 0.5 percent compared with 1998. This decline was mainly due to a $15 million net decrease in fuel and purchased power costs and a $23 million decrease in maintenance expense, offset by an increase in taxes other than income taxes of $12 million.

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:

	2000	1999	1998
Total generation (billions of KWHs)	**65**	63	63
Sources of generation (percent) --			
Coal	**72**	72	72
Nuclear	**19**	20	18
Hydro	**3**	5	8
Oil & Gas	**6**	3	2
Average cost of fuel per net KWH generated (cents) --	**1.54**	1.44	1.54

In 2000, total fuel and purchased power costs of $1.3 billion increased $183 million (16 percent), while total energy sales increased 4,658 million kilowatt hours (6.9 percent) compared with the amounts recorded in 1999. Fuel and purchased power costs in 1999 decreased $15 million (1 percent) compared to 1998.

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 2000, purchased power transactions among the Company and non-affiliates increased $72 million (77 percent) due to higher costs associated with these energy purchases and to offset decreased hydro generation, which was down significantly compared to 1999 as a result of lower stream flows.

The 8.4 percent increase in maintenance expense in 2000 as compared to 1999 is primarily attributable to an increase in the maintenance of overhead distribution lines and additional accruals to partially replenish the natural disaster reserve. The 7.5 percent decrease in maintenance expenses in 1999 is primarily attributable to a decrease in distribution expenses.

Depreciation and amortization expense increased 4.9 percent in 2000 and 2.6 percent in 1999. These increases reflect additions to property, plant, and equipment.

Taxes other than income taxes increased $5 million (2.5 percent) in 2000 as compared to 1999. This increase is attributable to increases in real and personal property taxes and public utility license taxes.

Total net interest and other charges increased $7 million (2.7 percent) in 2000. This increase results primarily from an increase in interest on long-term debt offset by a decrease in other interest charges. Total net interest and other charges decreased $38 million (12.3 percent) in 1999 primarily from a decrease in the amortization of premiums on reacquired debt pursuant to an APSC order. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional details.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of 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.

Future Earnings Potential

The results of 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 cost in a more competitive environment.

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 APSC under cost-based regulatory principles.

Future earnings for the traditional business in the near term will depend upon growth in energy sales, which 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 traditional service area.

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 cogeneration plants for a utility's large industrial and/or commercial customers and sell excess energy generation to other utilities. Also, electricity sales for resale rates are affected by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers 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 current energy crisis in California. As a result of this crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The inability of the Company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on the Company's financial statements.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. 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.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in the regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. Southern Company and its integrated southeast utility subsidiaries, including the Company, filed on October 16, 2000, a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of the Company and any other participating utilities. Participants would have the option to either maintain their ownership, divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on the Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUHCA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUHCA. These entities are able to own and operate power generating facilities and sell power to affiliates—under certain restrictions.

The Company is constructing 1,230 megawatts of wholesale generating facilities in Autaugaville, Alabama to begin operation in 2003. Half of this capacity has been certified by the APSC to serve the Company's retail customers for seven years. The other half of the capacity will be sold into the wholesale market and will not affect retail rates.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary—Southern Power Company (SPC). The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. SPC will be the primary growth engine for Southern Company's market-based energy business. Energy from its assets will be marketed to wholesale customers under the Southern Company name.

Currently, the Company plans to transfer the generating facilities under construction in Autaugaville to SPC in 2001. The Company will enter into a purchased power agreement for half of the capacity of these generating facilities to serve its territorial customers.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $54 million in 2000. Pension plan income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan. For more information, see Note 2.

Rates to retail customers served by the Company are regulated by the APSC. Rates for the Company can be adjusted periodically within certain limitations based on earned retail rate of return compared with an allowed return. There is a moratorium on any periodic retail rate increases (but not decreases) until July 2001.

In December 1995, the APSC issued an order authorizing the Company to reduce balance sheet items -- such as plant and deferred charges -- at any time the Company's actual base rate revenues exceed the budgeted revenues. In April 1997, the APSC issued an additional order authorizing the Company to reduce balance sheet asset items. This order authorizes the reduction of such items up to an amount equal to five times the total estimated annual revenue reduction resulting from future rate reductions initiated by the Company.

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 615 megawatts of the Company's wholesale generating facilities under construction in Autaugaville, Alabama, all of which will be delivered in 2003. In addition, the APSC certified a seven-year purchased power agreement with a third party for approximately 630 megawatts; one half of the power will be delivered in 2003 while the remaining half is scheduled for delivery in 2004.

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."

The staff of the Securities and Exchange Commission (SEC) has questioned certain of the current accounting practices of the electric utility industry -- including the Company -- regarding the recognition, measurement, and classification in the financial statements of decommissioning costs for nuclear generating facilities. In response to these questions, the FASB is reviewing the accounting for liabilities related to the retirement of long-lived assets, including nuclear decommissioning. If the FASB issues new accounting rules, the estimated costs of retiring the Company's nuclear and other facilities may be required to be recorded as liabilities in the Balance Sheets. Also, the annual provisions for such costs could change. Because of the Company's current ability to recover asset retirement costs through rates, these changes would not have a significant adverse effect on results of operations. See Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning" for additional information.

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 operations 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 Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

The Company utilizes financial instruments to reduce its exposure to changes in foreign currency exchange rates. The Company also enters into commodity related forward contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales.

Substantially all of the Company's bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted Statement No. 133 effective January 1, 2001, with no material impact. The application of the new rules is still evolving and further guidance from FASB is expected, which could additionally impact the Company's financial statements.

Exposure to Market Risk

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. Realized gains and losses are recognized in the income statement as incurred. At December 31, 2000, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. Also, based on the Company's overall interest rate exposure at December 31, 2000, a near-term 100 basis point change in interest rates would not materially affect the financial statements.

FINANCIAL CONDITION

Overview

The Company's financial condition remained stable in 2000. This stability is the continuation over recent years of growth in retail energy sales and cost control measures combined with a significant lowering of the 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 $871 million in 2000. 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.

Capital Structure

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 42.2 percent in 2000 and 42.4 percent in 1999 and 1998.

During 2000, the Company issued $250 million of senior notes, the proceeds of which were used primarily to repay short-term indebtedness.

Capital Requirements

Capital expenditures are estimated to be $735 million for 2001, $891 million for 2002, and $625 million for 2003. See Note 4 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; 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

The Company will continue to retire higher-cost debt and preferred stock and replace these obligations with lower-cost capital if market conditions permit.

Environmental Matters

In November 1990, the Clean Air Act Amendments (Clean Air Act) were signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected the integrated Southeast utility subsidiaries of Southern Company, including the Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995 and some 50 generating plants within the operating companies of Southern Company were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I compliance totaled approximately $25 million for the Company.

Phase II sulfur dioxide compliance was required in 2000. The Company used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits. Compliance with Phase II increased total construction expenditures through 2000 by $63 million

The one-hour ozone non-attainment standards for the Birmingham area have been set and must be implemented in May 2003. Two generating plants will be affected in the Birmingham area. Additional construction expenditures for compliance with these new rules are currently estimated at approximately $230 million.

In July 1997, the Environmental Protection Agency (EPA), revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U. S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states including Alabama. If standards and rules for implementation are upheld, the additional construction expenditures for compliance are estimated at approximately $189 million.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

On November 3, 1999, the EPA brought a civil action against the Company in the U. S. District Court. The complaint alleges violations of the prevention of significant deterioration and 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 a notice of violation to the Company 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. The complaint and notice of violation allege that the Company had 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. On August 1, 2000, the U.S. District Court granted the Company's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against the Company in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. The Company believes that it complied with applicable laws and EPA 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 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.

In December 2000, the EPA completed its utility studies for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls would likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including: control strategies to reduce regional haze; limits on pollutant discharges to impaired waters; water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. 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 costs and will recognize in the financial statements costs to clean up known sites. The Company has not incurred any cleanup costs to date.

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect the Company. The impact of new legislation – if any – will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electromagnetic fields.

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.

As required by the Nuclear Regulatory Commission and as ordered by the APSC, the Company has established external trust funds for nuclear decommissioning costs. 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 concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning."

Cautionary Statement Regarding Forward-Looking Information

This 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," "should," "expects," "plans," "anticipates," "believes," "estimates," "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 extent and timing of the entry of additional competition in the markets of the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the Company; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998
Alabama Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$2,952,707**	$2,811,117	$2,780,677
Sales for resale --			
Non-affiliates	**461,730**	415,377	448,973
Affiliates	**166,219**	92,439	103,562
Other revenues	**86,805**	66,541	53,161
Total operating revenues	**3,667,461**	3,385,474	3,386,373
Operating Expenses:			
Operation --			
Fuel	**963,275**	855,632	900,309
Purchased power --			
Non-affiliates	**164,881**	93,204	92,998
Affiliates	**184,014**	180,563	150,897
Other	**538,529**	531,696	527,954
Maintenance	**301,046**	277,724	300,383
Depreciation and amortization	**364,618**	347,574	338,822
Taxes other than income taxes	**209,673**	204,645	193,049
Total operating expenses	**2,726,036**	2,491,038	2,504,412
Operating Income	**941,425**	894,436	881,961
Other Income (Expense):			
Interest income	**38,167**	55,896	68,553
Equity in earnings of unconsolidated subsidiaries (Note 5)	**3,156**	2,650	5,271
Other, net	**(7,909)**	(24,861)	(37,050)
Earnings Before Interest and Income Taxes	**974,839**	928,121	918,735
Interest and Other:			
Interest expense, net	**251,663**	245,235	285,940
Distributions on preferred securities of subsidiary (Note 8)	**25,549**	24,662	22,354
Total interest and other, net	**277,212**	269,897	308,294
Earnings Before Income Taxes	**697,627**	658,224	610,441
Income taxes (Note 7)	**261,555**	241,880	218,575
Net Income	**436,072**	416,344	391,866
Dividends on Preferred Stock	**16,156**	16,464	14,643
Net Income After Dividends on Preferred Stock	**$ 419,916**	$ 399,880	$ 377,223

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Alabama Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	**$ 436,072**	$ 416,344	$ 391,866
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**412,998**	403,332	425,167
Deferred income taxes and investment tax credits, net	**66,166**	29,039	79,430
Other, net	**(37,703)**	(12,661)	(66,739)
Changes in certain current assets and liabilities --			
Receivables, net	**(125,652)**	33,509	49,747
Fossil fuel stock	**23,967**	(1,344)	(9,052)
Materials and supplies	**(10,662)**	(17,968)	11,932
Accounts payable	**107,702**	(38,556)	26,583
Energy cost recovery, retail	**(69,190)**	(97,869)	(95,427)
Other	**23,336**	5,930	(9,803)
Net cash provided from operating activities	**827,034**	719,756	803,704
Investing Activities:			
Gross property additions	**(870,581)**	(809,044)	(610,132)
Other	**(49,414)**	(72,218)	(52,940)
Net cash used for investing activities	**(919,995)**	(881,262)	(663,072)
Financing Activities:			
Increase (decrease) in notes payable, net	**184,519**	96,824	(306,882)
Proceeds --			
Other long-term debt	**250,000**	751,650	1,462,990
Preferred securities	**-**	50,000	-
Preferred stock	**-**	-	200,000
Capital contributions from parent company	**204,371**	204,347	30,000
Redemptions --			
First mortgage bonds	**(111,009)**	(470,000)	(771,108)
Other long-term debt	**(5,987)**	(104,836)	(107,776)
Preferred stock	**-**	(50,000)	(88,000)
Payment of preferred stock dividends	**(16,110)**	(15,788)	(15,596)
Payment of common stock dividends	**(417,100)**	(399,600)	(367,100)
Other	**(951)**	(15,864)	(66,869)
Net cash provided from financing activities	**87,733**	46,733	(30,341)
Net Change in Cash and Cash Equivalents	**(5,228)**	(114,773)	110,291
Cash and Cash Equivalents at Beginning of Period	**19,475**	134,248	23,957
Cash and Cash Equivalents at End of Period	**$ 14,247**	$ 19,475	$ 134,248
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$237,066**	$229,305	$234,360
Income taxes (net of refunds)	**175,303**	170,121	188,942

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Alabama Power Company 2000 Annual Report

Assets	2000	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 14,247**	$ 19,475
Receivables --		
Customer accounts receivable	**337,870**	265,900
Under-recovered retail fuel clause revenue	**237,817**	168,627
Other accounts and notes receivable	**60,315**	42,137
Affiliated companies	**95,704**	40,083
Accumulated provision for uncollectible accounts	**(6,237)**	(4,117)
Refundable income taxes	**-**	17,997
Fossil fuel stock, at average cost	**60,615**	84,582
Materials and supplies, at average cost	**178,299**	167,637
Other	**52,624**	46,011
Total current assets	**1,031,254**	848,332
Property, Plant, and Equipment:		
In service	**12,431,575**	11,783,078
Less accumulated provision for depreciation	**5,107,822**	4,901,384
	7,323,753	6,881,694
Nuclear fuel, at amortized cost	**94,050**	106,836
Construction work in progress	**744,974**	715,153
Total property, plant, and equipment	**8,162,777**	7,703,683
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries (Note 5)	**38,623**	34,891
Nuclear decommissioning trusts	**313,895**	286,653
Other	**13,612**	12,156
Total other property and investments	**366,130**	333,700
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 7)	**345,550**	330,405
Prepaid pension costs	**268,259**	213,971
Debt expense, being amortized	**8,758**	9,563
Premium on reacquired debt, being amortized	**76,020**	83,895
Department of Energy assessments	**24,588**	27,685
Other	**95,772**	97,470
Total deferred charges and other assets	**818,947**	762,989
Total Assets	**$10,379,108**	$9,648,704

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Alabama Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	2000	1999
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 10)	$ 844	$ 100,943
Notes payable	281,343	96,824
Accounts payable --		
Affiliated	124,534	91,315
Other	209,205	140,842
Customer deposits	36,814	31,704
Taxes accrued --		
Income taxes	65,505	100,569
Other	19,471	18,295
Interest accrued	33,186	26,365
Vacation pay accrued	31,711	30,112
Other	97,743	84,267
Total current liabilities	900,356	721,236
Long-term debt (See accompanying statements)	3,425,527	3,190,378
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 7)	1,401,424	1,240,344
Deferred credits related to income taxes (Note 7)	222,485	265,102
Accumulated deferred investment tax credits	249,280	260,367
Employee benefits provisions	84,816	82,298
Prepaid capacity revenues (Note 6)	58,377	79,703
Other	176,559	155,901
Total deferred credits and other liabilities	2,192,941	2,083,715
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements) (Note 8)	347,000	347,000
Cumulative preferred stock (See accompanying statements)	317,512	317,512
Common stockholder's equity (See accompanying statements)	3,195,772	2,988,863
Total Liabilities and Stockholder's Equity	$10,379,108	$9,648,704

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Alabama Power Company 2000 Annual Report

		2000	1999	2000	1999
			(in thousands)	*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
March 1, 2000	6.00%	$ -	$ 100,000		
2023 through 2024	7.30% - 9.00%	**488,991**	500,000		
Total first mortgage bonds		**488,991**	600,000		
Senior notes --					
5.35% due November 15, 2003		**156,200**	156,200		
7.850% due May 15, 2003		**250,000**	-		
7.125% due August 15, 2004		**250,000**	250,000		
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		
6.25% to 7.125% due 2010-2048		**1,202,581**	1,207,622		
Total senior notes		**2,443,781**	2,198,822		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.50% due 2024		**24,400**	24,400		
Variable rates (4.73% to 5.05% at 1/1/01) due 2015-2017		**89,800**	89,800		
Non-collateralized:					
6.69% due 2021		**65,000**	-		
Variable rates (3.50% to 5.30% at 1/1/01) due 2021-2028		**360,940**	425,940		
Total other long-term debt (Note 9)		**540,140**	540,140		
Capitalized lease obligations		**4,165**	5,111		
Unamortized debt premium (discount), net		**(50,706)**	(52,752)		
Total long-term debt (annual interest requirement -- $179.6 million)		**3,426,371**	3,291,321		
Less amount due within one year		**844**	100,943		
Long-term debt excluding amount due within one year		**$3,425,527**	$3,190,378	**46.9%**	46.6%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2000 and 1999
Alabama Power Company 2000 Annual Report

	2000	1999	2000	1999
		(in thousands)	*(percent of total)*	
Company Obligated Mandatorily Redeemable Preferred Securities: (Note 8)				
$25 liquidation value --				
7.375%	**$ 97,000**	$ 97,000		
7.60%	**200,000**	200,000		
Auction rate (6.52% at 1/1/01)	**50,000**	50,000		
Total (annual distribution requirement -- $25.6 million)	**347,000**	347,000	**4.8**	5.1
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 1/1/01				
5.14% to 5.25%	**70,000**	70,000		
Total (annual dividend requirement -- $16.5 million)	**317,512**	317,512	**4.4**	4.6
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 6,000,000 shares				
Outstanding - 5,608,955 shares in 2000 and 1999				
Par value	**224,358**	224,358		
Paid-in capital	**1,743,363**	1,538,992		
Premium on Preferred Stock	**99**	99		
Retained earnings	**1,227,952**	1,225,414		
Total common stockholder's equity	**3,195,772**	2,988,863	**43.9**	43.7
Total Capitalization	**$7,285,811**	$6,843,753	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2000, 1999, and 1998
Alabama Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1998	$224,358	$1,304,645	$99	$1,221,467	$2,750,569
Net income after dividends on preferred stock	-	-	-	377,223	377,223
Capital contributions from parent company	-	30,000	-	-	30,000
Cash dividends on common stock	-	-	-	(367,100)	(367,100)
Other	-	-	-	(6,625)	(6,625)
Balance at December 31, 1998	224,358	1,334,645	99	1,224,965	2,784,067
Net income after dividends on preferred stock	-	-	-	399,880	399,880
Capital contributions from parent company	-	204,347	-	-	204,347
Cash dividends on common stock	-	-	-	(399,600)	(399,600)
Other	-	-	-	169	169
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

The accompanying notes are an integral part of these 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 integrated Southeast utilities, a system service company (SCS), Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Southern Nuclear Operating Company (Southern Nuclear), Mirant Corporation—formerly Southern Energy, Inc.-- and other direct and indirect subsidiaries. The integrated Southeast utilities -- Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company-- provide electric service in four states. Contracts among the integrated Southeast utilities – related to jointly-owned generating facilities, interconnecting transmission lines, and the exchange of electric power – are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). SCS provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern LINC provides digital wireless communications services to the integrated Southeast utilities and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

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.

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, 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 $187 million, $218 million, and $201 million during 2000, 1999, and 1998, respectively.

The Company also 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, and employee relations; and other services with respect to business and operations. Costs for these services amounted to $148 million, $135 million, and $137 million during 2000, 1999, and 1998, respectively.

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:

	2000	1999
	(in millions)	
Deferred income tax charges	**$ 346**	$ 330
Deferred income tax credits	**(222)**	(265)
Premium on reacquired debt	**76**	84
Department of Energy assessments	**25**	28
Vacation pay	**32**	30
Natural disaster reserve	**(18)**	(19)
Other, net	**30**	59
Total	**$ 269**	$ 247

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.

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 revenues have no effect on net income because they represent the recording of revenues to offset fuel expenses, including the fuel component of purchased energy. Fuel rates billed to customers are designed to fully recover fluctuating fuel costs over a period of time. Higher natural gas prices and decreased hydro production combined with increased costs of purchased power have resulted in a large under-recovery of fuel costs at December 31, 2000. Effective January 2001, the Company's fuel rate was increased to address this under-recovery. The Company expects to significantly reduce this balance over a three-year period.

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 $61 million in 2000, $63 million in 1999, and $59 million in 1998.

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 as early as 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 $25 million at December 31, 2000. This obligation is recognized 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 2000, 1999 and 1998. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost -- together with the cost of removal, less salvage -- is charged to accumulated provision for 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.

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 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 basis (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 2000 and fund balances as of December 31, 2000 were:

	(in millions)
Amount expensed in 2000	**$ 18**
Accumulated provisions:	
External trust funds, at fair value	$314
Internal reserves	38
Total	$352

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.

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)

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new 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. The amount of AFUDC capitalized was $43 million in 2000, $23 million in 1999, and $9 million in 1998. The composite rate used to determine the amount of allowance was 9.6 percent in 2000, 8.8 percent in 1999, and 9.0 percent in 1998. AFUDC, net of income tax, as a percent of net income after dividends on preferred stock was 8.4 percent in 2000, 4.7 percent in 1999, and 1.8 percent in 1998.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. 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 maintenance, repairs and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property--exclusive of minor items of property--is capitalized.

Financial Instruments

The Company uses derivative financial instruments to hedge exposures to fluctuations in foreign currency exchange rates and certain commodity prices. Gains and losses on qualifying hedges are deferred and recognized either in income or as an adjustment to the carrying amount of the hedged item when the transaction occurs.

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. The Company is unaware of any counterparties that will fail to meet their obligations.

The Company has firm purchase commitments for equipment that require payment in euros. As a hedge against fluctuations in the exchange rate for euros, the Company entered into forward currency swaps. The notional amount is 16 million euros maturing in 2001 through 2002. At December 31, 2000, the unrecognized gain on these swaps was approximately $1 million.

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2000	**$3,422**	**$3,375**
At December 31, 1999	3,286	3,045
Preferred Securities:		
At December 31, 2000	**347**	**344**
At December 31, 1999	347	299

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

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. At December 31, 2000, the reserve balance was $18 million.

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed, pension plans that cover substantially all 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 FERC.

In late 2000, the Company adopted several pension and postretirement benefit plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits cost by approximately $8 million and $12 million, respectively.

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:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00**	5.00
Long-term return on plan assets	**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	
	2000	1999
	(in millions)	
Balance at beginning of year	**$873**	$868
Service cost	**22**	23
Interest cost	**64**	57
Benefits paid	**(51)**	(51)
Actuarial gain and employee transfers	**(8)**	(24)
Balance at end of year	**$900**	$873

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$1,647**	$1,461
Actual return on plan assets	**302**	245
Benefits paid	**(51)**	(51)
Employee transfers	**23**	(8)
Balance at end of year	**$1,921**	$1,647

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

	2000	1999
	(in millions)	
Funded status	**$1,021**	$ 774
Unrecognized transition obligation	**(21)**	(25)
Unrecognized prior service cost	**33**	36
Unrecognized net actuarial gain	**(765)**	(571)
Prepaid asset recognized in the Balance Sheets	**$ 268**	$ 214

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

	2000	1999	1998
	(in millions)		
Service cost	**$ 23**	$ 23	$ 22
Interest cost	**64**	57	59
Expected return on plan assets	**(119)**	(109)	(102)
Recognized net actuarial gain	**(20)**	(14)	(16)
Net amortization	**(2)**	(2)	(2)
Net pension income	**$ (54)**	$ (45)	$(39)

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	
	2000	1999
	(in millions)	
Balance at beginning of year	**$264**	$278
Service cost	**4**	5
Interest cost	**19**	18
Benefits paid	**(12)**	(10)
Actuarial gain and employee transfers	**(11)**	(27)
Balance at end of year	**$264**	$264

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$161**	$137
Actual return on plan assets	**25**	18
Employer contributions	**18**	16
Benefits paid	**(12)**	(10)
Balance at end of year	**$192**	$161

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

	2000	1999
	(in millions)	
Funded status	**$(72)**	$(103)
Unrecognized transition obligation	**49**	53
Unrecognized net actuarial gain	**(35)**	(12)
Fourth quarter contributions	**4**	8
Accrued liability recognized in the Balance Sheets	**$(54)**	$ (54)

Components of the plans' net periodic cost were as follows:

	2000	1999	1998
	(in millions)		
Service cost	**$ 4**	$ 5	$ 5
Interest cost	**19**	18	18
Expected return on plan assets	**(13)**	(11)	(9)
Net amortization	**4**	4	4
Net postretirement cost	**$ 14**	$16	$18

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005, 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$15	$14
Service and interest costs	1	1

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 2000, 1999, and 1998 were $11 million, $10 million, and $10 million, respectively.

Work Force Reduction Programs

The Company has incurred costs for work force reduction programs totaling $2.6 million, $5.6 million and $19.4 million for the years 2000, 1999 and 1998, respectively. These costs were deferred and are being amortized in accordance with regulatory treatment. The unamortized balance of these costs was $1.4 million at December 31, 2000.

3. CONTINGENCIES AND REGULATORY MATTERS

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA), brought a civil action against the Company in the U. S. District Court. The complaint alleges violations of the prevention of significant deterioration and new source review provision 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. On August 1, 2000, the U.S. District Court granted the Company's motion to dismiss for lack of jurisdiction in Georgia and granted SCS's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against the Company in federal district court in Birmingham, Alabama. The EPA did not include SCS in the new complaint. 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. The rates also provide for adjustments to recognize the placing of new generating facilities into retail service. Both increases and decreases have been placed into effect since the adoption of these rates. The rate adjustment procedures allow a return on common equity range of 13.0 percent to 14.5 percent and limit increases or decreases in rates to 4 percent in any calendar year. There is a moratorium on any periodic retail rate increases (but not decreases) until July 2001.

In December 1995, the APSC issued an order authorizing the Company to reduce balance sheet items -- such as plant and deferred charges -- at any time the Company's actual base rate revenues exceed the budgeted revenues. In April 1997, the APSC issued an additional order authorizing the Company to reduce balance sheet asset items. This order authorizes the reduction of such items up to an amount equal to five times the total estimated annual revenue reduction resulting from future rate reductions initiated by the Company. In 1998, the Company – in accordance with the 1995 rate order – recorded $33 million of additional amortization of premium on reacquired debt. The Company did not record any additional amounts in 2000 or 1999.

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 615 megawatts of the Company's wholesale generating facilities under construction in Autaugaville, Alabama, all of which will be delivered in 2003. In addition, the APSC certified a seven-year purchased power agreement with a third party for approximately 630 megawatts; one half of the power will be delivered in 2003 while the remaining half is scheduled for delivery in 2004.

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

4. FINANCING AND COMMITMENTS

Construction Program

To the extent possible, the Company's construction program is expected to be financed primarily from internal sources. Short-term debt is often utilized and the amounts available are discussed below. The Company may issue additional long-term debt and preferred securities for debt maturities, redeeming higher-cost securities, and meeting additional capital requirements.

The Company currently estimates property additions to be $735 million in 2001, $891 million in 2002, and $625 million in 2003.

The Company is constructing 1,230 megawatts of wholesale generating facilities in Autaugaville, Alabama to begin operation in 2003. Half of this capacity has been certified by the APSC to serve the Company's retail customers for seven years. The other half of the capacity will be sold into the wholesale market and will not affect retail rates. During 2001, the Company plans to transfer these generating facilities to Southern Power Company (SPC), the new wholesale subsidiary formed by Southern Company. If the Company transfers wholesale generation assets to SPC as planned, construction expenditures for the years 2001 through 2003 will be $598 million, $591 million and $583 million, respectively.

During 2001, the Company expects to complete the replacement of the steam generators at Plant Farley, as well as the construction of new generating capacity at Plant Barry. In addition, significant construction will continue related to transmission and distribution facilities and the upgrading of generating plants, including the expenditures necessary to comply with environmental regulation.

The capital budget is subject to periodic review and revision, and actual capital costs incurred may vary from estimates because of changes in such factors as: business conditions; environmental regulations; nuclear plant 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.

Financing

The ability of the Company to finance its capital budget depends on the amount of funds generated internally and the funds it can raise by external financing. 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.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $925 million (including $418 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds). Of these lines, $535 million expire at various times during 2001 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. 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. Moreover, the Company borrows from time to time pursuant to arrangements with banks for uncommitted lines of credit.

At December 31, 2000, the Company had regulatory approval to have outstanding up to $750 million of short-term borrowings.

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.

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, 2000 were as follows:

Year	Commitments (in millions)
2001	$ -
2002	-
2003	16
2004	34
2005	37
2006 and beyond	180
Total commitments	$ 267

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, 2000, were as follows:

Year	Commitments (in millions)
2001	$ 998
2002	841
2003	722
2004	669
2005	525
2006 – 2024	2,287
Total commitments	$6,042

Operating Leases

The Company has entered into coal rail car rental agreements with various terms and expiration dates. These expenses totaled $20.9 million in 2000, $17.8 million in 1999, and $5.8 million in 1998. At December 31, 2000, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Commitments (in millions)
2001	$ 22.2
2002	21.6
2003	21.2
2004	18.2
2005	15.5
2006 – 2017	44.7
Total minimum payments	$143.4

5. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power Company 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 Company 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 $85 million in 2000, $92 million in 1999 and $74 million in 1998, 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 Company 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, 2000, the capitalization of SEGCO consisted of $51 million of equity and $78 million of long-term debt on which the annual interest requirement is $5.3 million. SEGCO paid dividends totaling $5.1 million in 2000, $4.3 million in 1999, and $8.7 million in 1998, of which one-half of each was paid to the Company. SEGCO's net income was $5.9 million, $5.4 million, and $7.5 million for 2000, 1999 and 1998, respectively.

The Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2000, 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 (in millions)	Accumulated Depreciation
Greene County	**$100**	**$ 46**
Plant Miller Units 1 and 2	**743**	**312**

6. LONG-TERM POWER SALES AGREEMENTS

General

The Company and the other integrated utility subsidiaries of Southern Company have entered into long-term contractual agreements for the sale of capacity and energy to certain non-affiliated utilities located outside the system's service area. These agreements -- expiring at various dates discussed below -- are firm and pertain to capacity related to specific generating units. Because the energy is generally sold at cost under these agreements, profitability is primarily affected by revenues from capacity sales. The Company's capacity revenues amounted to $127 million in 2000, $122 million in 1999, and $142 million in 1998.

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 1,235 megawatts of capacity are scheduled to be sold through 2001. Thereafter, these sales will remain at that approximate level -- unless reduced by FP&L, FPC, and JEA for the periods after 2001 with a minimum of three years notice -- until the expiration of the contracts in 2010. No notices of cancellation have been received.

Alabama Municipal Electric Authority (AMEA) Capacity Contracts

In August 1986, the Company entered into a firm power sales contract with AMEA entitling AMEA to scheduled amounts of capacity (to a maximum 100 megawatts) for a period of 15 years commencing September 1, 1986 (1986 Contract). In October 1991, the Company entered into a second firm power sales contract with AMEA entitling AMEA to scheduled amounts of additional capacity (to a maximum 80 megawatts) for a period of 15 years commencing October 1, 1991 (1991 Contract). In both contracts the power will be sold to AMEA for its member municipalities that previously were served directly by the Company as wholesale customers. Under the terms of the contracts, the Company received payments from AMEA representing the net present value of the revenues associated with the respective capacity entitlements, discounted at effective annual rates of 9.96 percent and 11.19 percent for the 1986 and 1991 contracts, respectively. These payments are being recognized as operating revenues and the discounts are being amortized to other interest expense as scheduled capacity is made available over the terms of the contracts.

In order 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 under the contracts, a portion of the bonds equal to the decreases is returned to the Company. At December 31, 2000, $61.3 million of such bonds were held by the escrow agent under the contracts.

7. INCOME TAXES

At December 31, 2000, the tax-related regulatory assets and liabilities were $346 million and $222 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:

	2000	1999	1998
	(in millions)		
Total provision for income taxes:			
Federal --			
Current	**$168**	$194	$123
Deferred	**60**	24	72
	228	218	195
State --			
Current	**27**	19	16
Deferred	**7**	5	7
	34	24	23
Total	**$262**	$242	$218

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:

	2000	1999
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$ 992**	$ 884
Property basis differences	**405**	419
Fuel cost adjustment	**93**	65
Premium on reacquired debt	**30**	31
Pensions	**75**	60
Other	**12**	11
Total	**1,607**	1,470
Deferred tax assets:		
Capacity prepayments	**18**	24
Other deferred costs	**14**	25
Postretirement benefits	**24**	22
Unbilled revenue	**23**	13
Other	**81**	63
Total	**160**	147
Net deferred tax liabilities	**1,447**	1,323
Portion included in current liabilities, net	**(46)**	(83)
Accumulated deferred income taxes in the Balance Sheets	**$1,401**	$1,240

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 2000, 1999, and 1998. At December 31, 2000, 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:

	2000	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.1**	2.4	2.5
Non-deductible book depreciation	**1.4**	1.6	1.5
Differences in prior years' deferred and current tax rates	**(1.3)**	(1.3)	(1.6)
Other	**(0.7)**	(0.9)	(1.6)
Effective income tax rate	**37.5%**	36.8%	35.8%

Southern Company files a consolidated federal and certain state income tax returns. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis.

8. COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES

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

	Date of Issue	Amount (millions)	Rate	Notes (millions)	Maturity Date
Trust I	1/1996	$ 97	7.375%	$100	3/2026
Trust II	1/1997	200	7.60	206	12/2036
Trust III	2/1999	50	Auction	52	2/2029

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 distribution rate of Trust III's auction rate securities was 6.52% at January 1, 2001.

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.

9. OTHER LONG-TERM DEBT

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.

In May 2000, the Company issued $250 million of unsecured senior notes. The proceeds of this issuance were used to repay short-term indebtedness. All of the Company's senior notes are, in effect, subordinated to all secured debt of the Company, including its first mortgage bonds.

The estimated aggregate annual maturities of capitalized lease obligations through 2005 are as follows: $0.8 million in 2001, $0.9 million in 2002, $0.9 million in 2003, $1.0 million in 2004 and $0.1 million in 2005.

10. 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:

	2000	1999
	(in thousands)	
First mortgage bond maturities and redemptions	**$ -**	$100,000
Other long-term debt maturities (Note 9)	**844**	943
Total long-term debt due within one year	**$844**	$100,943

The annual first mortgage bond improvement fund requirement is 1 percent of the aggregate principal amount of bonds of each series authenticated, so long as a portion of that series is outstanding, and may be satisfied by the deposit of cash and/or reacquired bonds, the certification of unfunded property additions, or a combination thereof.

11. 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 $200 million by private insurance, 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 be insured against increased costs of replacement power in an amount up to $3.5 million per week (starting 12 weeks after the outage) for one year and up to $2.8 million per week for the second and third years.

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 $17 million.

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.

12. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture contains various common stock dividend restrictions that remain in effect as long as the bonds are outstanding. At December 31, 2000, retained earnings of $796 million were restricted against the payment of cash dividends on common stock under terms of the mortgage indenture.

13. QUARTERLY FINANCIAL INFORMATION (Unaudited)

Summarized quarterly financial data for 2000 and 1999 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2000	**$ 746**	**$172**	**$ 68**
June 2000	**900**	**229**	**103**
September 2000	**1,137**	**390**	**209**
December 2000	**884**	**151**	**40**
March 1999	$ 714	$162	$ 63
June 1999	823	209	93
September 1999	1,116	388	201
December 1999	733	136	43

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

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SELECTED FINANCIAL AND OPERATING DATA 1996-2000

Alabama Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)	**$3,667,461**	$3,385,474	$3,386,373	$3,149,111	$3,120,775
Net Income after Dividends on Preferred Stock (in thousands)	**$419,916**	$399,880	$377,223	$375,939	$371,490
Cash Dividends on Common Stock (in thousands)	**$417,100**	$399,600	$367,100	$339,600	$347,500
Return on Average Common Equity (percent)	**13.58**	13.85	13.63	13.76	13.75
Total Assets (in thousands)	**$10,379,108**	$9,648,704	$9,225,698	$8,812,867	$8,733,846
Gross Property Additions (in thousands)	**$870,581**	$809,044	$610,132	$451,167	$425,024
Capitalization (in thousands):					
Common stock equity	**$3,195,772**	$2,988,863	$2,784,067	$2,750,569	$2,714,277
Preferred stock	**317,512**	317,512	317,512	255,512	340,400
Company obligated mandatorily redeemable preferred securities	**347,000**	347,000	297,000	297,000	97,000
Long-term debt	**3,425,527**	3,190,378	2,646,566	2,473,202	2,354,006
Total (excluding amounts due within one year)	**$7,285,811**	$6,843,753	$6,045,145	$5,776,283	$5,505,683
Capitalization Ratios (percent):					
Common stock equity	**43.9**	43.7	46.1	47.6	49.3
Preferred stock	**4.4**	4.6	5.3	4.4	6.2
Company obligated mandatorily redeemable preferred securities	**4.8**	5.1	4.9	5.2	1.7
Long-term debt	**46.9**	46.6	43.7	42.8	42.8
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	AA-*	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	A-	A	A	A
Fitch	**A***	A	A	A+	A+
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	-
Standard and Poor's	**A**	A	A	A	-
Fitch	**A+***	A+	A+	A+	-
Customers (year-end):					
Residential	**1,132,410**	1,120,574	1,106,217	1,092,161	1,073,559
Commercial	**193,106**	188,368	182,738	177,362	171,827
Industrial	**4,819**	4,897	5,020	5,076	5,100
Other	**745**	735	733	728	732
Total	**1,331,080**	1,314,574	1,294,708	1,275,327	1,251,218
Employees (year-end):	**6,871**	6,792	6,631	6,531	6,865

*Effective 1/22/01 the Fitch Security Ratings for First Mortgage Bonds, Preferred Stock, and Unsecured Long-Term Debt are A+, A-, and A respectively.

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Alabama Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands):					
Residential	**$ 1,222,509**	$1,145,646	$ 1,133,435	$ 997,507	$ 998,806
Commercial	**854,695**	807,098	779,169	724,148	696,453
Industrial	**859,668**	843,090	853,550	775,591	759,628
Other	**15,835**	15,283	14,523	13,563	13,729
Total retail	**2,952,707**	2,811,117	2,780,677	2,510,809	2,468,616
Sales for resale - non-affiliates	**461,730**	415,377	448,973	431,023	391,669
Sales for resale - affiliates	**166,219**	92,439	103,562	161,795	216,620
Total revenues from sales of electricity	**3,580,656**	3,318,933	3,333,212	3,103,627	3,076,905
Other revenues	**86,805**	66,541	53,161	45,484	43,870
Total	**$3,667,461**	$3,385,474	$3,386,373	$3,149,111	$3,120,775
Kilowatt-Hour Sales (in thousands):					
Residential	**16,771,821**	15,699,081	15,794,543	14,336,408	14,593,761
Commercial	**12,988,728**	12,314,085	11,904,509	11,330,312	10,904,476
Industrial	**22,101,407**	21,942,889	21,585,117	20,727,912	19,999,258
Other	**205,827**	201,149	196,647	180,389	192,573
Total retail	**52,067,783**	50,157,204	49,480,816	46,575,021	45,690,068
Sales for resale - non-affiliates	**14,847,533**	12,437,599	11,840,910	12,329,480	9,491,237
Sales for resale - affiliates	**5,369,474**	5,031,781	5,976,099	8,993,326	10,292,066
Total	**72,284,790**	67,626,584	67,297,825	67,897,827	65,473,371
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.29**	7.30	7.18	6.96	6.84
Commercial	**6.58**	6.55	6.55	6.39	6.39
Industrial	**3.89**	3.84	3.95	3.74	3.80
Total retail	**5.67**	5.60	5.62	5.39	5.40
Sales for resale	**3.11**	2.91	3.10	2.78	3.07
Total sales	**4.95**	4.91	4.95	4.57	4.70
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,875**	14,097	14,370	13,254	13,705
Residential Average Annual Revenue Per Customer	**$1,084.26**	$1,028.76	$1,031.21	$922.21	$937.95
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,122**	11,379	11,151	11,151	11,151
Maximum Peak-Hour Demand (megawatts):					
Winter	**9,478**	8,863	7,757	8,478	8,413
Summer	**11,019**	10,739	10,329	9,778	9,912
Annual Load Factor (percent)	**59.3**	59.7	62.9	62.7	61.3
Plant Availability (percent):					
Fossil-steam	**89.4**	80.4	85.6	86.3	86.6
Nuclear	**88.3**	91.0	80.2	88.8	90.5
Source of Energy Supply (percent):					
Coal	**63.0**	64.1	65.3	65.7	67.0
Nuclear	**16.9**	17.8	16.3	17.9	18.5
Hydro	**2.9**	4.7	6.9	7.5	7.1
Oil and gas	**4.9**	1.1	1.5	0.7	0.4
Purchased power -					
From non-affiliates	**4.6**	4.5	3.3	2.4	2.4
From affiliates	**7.7**	7.8	6.7	5.8	4.6
Total	**100.0**	100.0	100.0	100.0	100.0

GEORGIA POWER COMPANY

FINANCIAL SECTION

The management of Georgia Power Company has prepared this annual report and is responsible for the financial statements and related information. 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 based upon the recognition that the cost of the system should not exceed its benefits. The Company believes that 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 audit committee of the board of directors, which is composed of three independent directors, provides a broad overview of management's financial reporting and control functions. At least three times a year this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal control and financial reporting matters. The internal auditors and the independent public accountants have access to the members of the audit committee at any time.

Management believes that its policies and procedures provide reasonable assurance that the Company's operations are conducted with 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 Georgia Power Company in conformity with accounting principles generally accepted in the United States.

David M. Ratcliffe
President and Chief
Executive Officer

Thomas A. Fanning
Executive Vice President,
Treasurer and Chief
Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Georgia Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (a Georgia corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2000 and 1999, 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, 2000. 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 II-88 through II-108) referred to above present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Georgia Power Company's 2000 earnings totaled $559 million, representing an $18 million (3.3 percent) increase over 1999. This earnings increase is primarily due to higher retail and wholesale sales and continued control of operating expenses, partially offset by additional accelerated amortization of regulatory assets allowed under the second year of a Georgia Public Service Commission (GPSC) three-year retail rate order. Georgia Power Company's 1999 earnings totaled $541 million, representing a $29 million (5.1 percent) decrease from 1998. This earnings decrease was primarily due to the recognition of interest income in 1998 as a result of the resolution of tax issues with the Internal Revenue Service (IRS). Earnings in 1999 from normal operations increased due primarily to lower accelerated depreciation under the GPSC retail rate order, sales growth, and decreased financing costs, partially offset by retail rate reductions under the new order and lower wholesale revenues.

Revenues

Operating revenues in 2000 and the amount of change from the prior year are as follows:

	Amount	Increase (Decrease) From Prior Year	
	2000	2000	1999
		(in millions)	
Retail -			
Base revenues	**$3,119**	**$ 84**	$(292)
Fuel cost recovery	**1,198**	**183**	44
Total retail	**4,317**	**267**	(248)
Sales for resale -			
Non-affiliates	**298**	**88**	(49)
Affiliates	**96**	**20**	(5)
Total sales for resale	**394**	**108**	(54)
Other operating revenues	**160**	**39**	21
Total operating revenues	**$4,871**	**$414**	$(281)
Percent change		**9.3%**	(5.9)%

Retail base revenues of $3.1 billion in 2000 increased $84 million (2.8 percent) primarily due to a 4.9 percent increase in sales. Under the GPSC retail rate order, the Company recorded $44 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity in 2000. Refunds will be made to customers in 2001. Retail base revenues of $3.0 billion in 1999 decreased $292 million (8.8 percent) primarily due to retail rate reductions under the GPSC retail rate order. Pursuant to the GPSC retail rate order, in 1999 the Company also recorded $79 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity. Revenue subject to refund is reflected in "Base revenues" in the chart above. The $79 million in refunds were made to customers in 2000. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses -- including the fuel component of purchased energy -- and do not affect net income. However cash flow is affected by the untimely recovery of these receivables. As of December 31, 2000, the Company had $132 million in underrecovered fuel costs. The Company currently plans to make a filing with the GPSC in early 2001 to establish a new fuel rate in order to better reflect current fuel cost and to collect the current underrecovered balance.

Wholesale revenues from sales to non-affiliated utilities increased in 2000 and decreased in 1999 as follows:

	2000	1999	1998
	(in millions)		
Outside service area -			
Long-term contracts	**$ 55**	$ 55	$ 51
Other sales	**162**	74	93
Inside service area	**81**	81	115
Total	**$298**	$210	$259

Revenues from long-term contracts outside the service area remained constant in 2000 and increased slightly in 1999 due to increased energy sales. See Note 7 to the financial statements for further information regarding these sales. Revenues from other sales outside the service area primarily represent wholesale sales from Plant Dahlberg which went into service during 2000 and increases in power marketing activities. These activities include the purchase and resale of energy. Consequently, changes in revenues are generally offset by corresponding changes in purchased power expense from non-affiliates. Wholesale revenues from customers within the service area remained constant in 2000 but decreased in 1999 primarily due to a decrease in revenues under a power supply agreement with Oglethorpe Power Corporation (OPC).

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 do not have a significant impact on earnings.

Other operating revenues in 2000 increased $39 million (33 percent) primarily due to increased revenues from the transmission of electricity and gains on the sale of generating plant emission allowances. Under a GPSC order, $28 million of the gains on emission allowance sales in 2000 were used to reduce recoverable fuel costs and as such, did not affect earnings. In 1999, other operating revenues increased $21 million or (21 percent) from the previous year due primarily to increased revenues from the rental of electric equipment and property.

Kilowatt-hour (KWH) sales for 2000 and the percent change by year were as follows:

	2000 KWH (in billions)	Percent Change 2000	Percent Change 1999
Residential	**20.7**	**6.6%**	(0.4)%
Commercial	**25.6**	**8.1**	3.7
Industrial	**27.5**	**0.9**	0.1
Other	**0.6**	**3.2**	1.5
Total retail	**74.4**	**4.9**	1.1
Sales for resale -			
Non-affiliates	**6.5**	**27.7**	(21.4)
Affiliates	**2.4**	**35.6**	(11.9)
Total sales for resale	**8.9**	**29.8**	(19.1)
Total sales	**83.3**	**7.1**	(1.0)

Residential and commercial sales increased 6.6 percent and 8.1 percent, respectively, due to warmer summer temperatures and colder winter weather. Strong regional economic growth was also a factor in the increase in commercial sales. Industrial sales remained fairly constant. In 1999, residential sales decreased 0.4 percent due to moderate summer temperatures, while commercial sales increased 3.7 percent due to strong regional economic growth. Industrial sales remained fairly constant.

Expenses

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:

	2000	1999	1998
Total generation (billions of KWH)	**73.6**	69.3	69.1
Sources of generation (percent) --			
Coal	**75.8**	75.5	73.3
Nuclear	**21.2**	21.6	21.6
Hydro	**0.8**	1.0	2.6
Oil and gas	**2.2**	1.9	2.5
Average cost of fuel per net KWH generated (cents) --	**1.39**	1.34	1.36

Fuel expense increased 10.7 percent in 2000 due to an increase in generation to meet higher energy demands, a decrease in generation from hydro plants, and a higher average cost of fuel. Fuel expense increased 0.3 percent in 1999 due to a slight increase in fossil and nuclear generation and a decrease in generation from hydro plants, partially offset by a lower average cost of fuel.

Purchased power expense in 2000 increased $206 million (53 percent) over the prior year due to higher retail energy demands and power marketing activities. The majority of the increase was offset by increases in retail fuel revenues and power marketing revenues and therefore did not affect earnings. As discussed above, the expense associated with energy purchased for power marketing activities is generally offset by revenue when resold. Purchased power expense decreased slightly in 1999.

Other operation and maintenance expenses in 2000 increased slightly over those in 1999. Increased line maintenance, customer assistance and sales expense and additional severance costs were partially offset by decreased generating plant maintenance and decreased employee benefit provisions. Other operation and maintenance expenses increased 1.6 percent in 1999 primarily due to increased generating plant maintenance, partially offset by a reduction in the charges related to the implementation of a customer service system in 1998, decreased year 2000 readiness costs, and decreased employee benefit provisions.

Depreciation and amortization increased $66 million in 2000 due to $50 million of additional accelerated amortization of regulatory assets required under the second year of the GPSC retail rate order and increased plant in service. Depreciation and amortization decreased $261 million in 1999 primarily due to higher depreciation charges recognized in 1998 under the prior GPSC accounting order and the completion in 1998 of the amortization of deferred Plant Vogtle costs.

Interest income decreased $3 million in 2000 primarily due to decreased interest on temporary cash investments. Interest income decreased in 1999 primarily due to the 1998 recognition of $73 million in interest income resulting from the resolution of tax issues with the IRS and the State of Georgia. Other, net decreased in 2000 due to an increase in charitable contributions. In 1999, other, net decreased due primarily to increased bad debt expense related to consumer energy efficiency improvement financing.

Interest expense, net increased in 2000 due to the issuance of an additional $300 million in senior notes during 2000. Interest expense, net decreased in 1999 due primarily to the refinancing or retirement of securities. The Company refinanced or retired $179 million and $775 million of securities in 2000 and 1999, respectively. Distributions on preferred securities of subsidiary companies decreased $7 million in 2000 due to the redemption of $100 million of preferred securities in December 1999. Distributions on preferred securities of subsidiary companies increased $11 million in 1999 due to the issuance of additional mandatorily redeemable preferred securities in January 1999.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of 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 plants with long economic life. 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.

FUTURE EARNINGS POTENTIAL

The results of operations for the past three years are not necessarily indicative of future earnings. The level of future earnings depends on numerous factors including regulatory matters and energy sales.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in the State of Georgia. Prices for electricity provided by the Company to retail customers are set by the GPSC under cost-based regulatory principles.

On January 1, 1999, the Company began operating under a new three-year retail rate order. The Company's earnings are evaluated against a retail return on common equity range of 10 percent to 12.5 percent, with required rate reductions of $262 million on an annual basis effective in 1999 and an additional $24 million effective in 2000. The order provides for $85 million in each year, plus up to $50 million of any earnings above the 12.5 percent return during the second and third years, to be applied to accelerated amortization or depreciation of assets. Two-thirds of any additional earnings above the 12.5 percent return will be applied to rate reductions, with the remaining one-third retained by the Company. Pursuant to the GPSC retail rate order, in 2000 and 1999, the Company recorded $85 million in accelerated amortization of regulatory assets. In 2000, the Company also recorded the additional $50 million of accelerated amortization. The accelerated amortization is recorded in a regulatory liability account as mandated by the GPSC. In addition, the Company recorded $44 million and $79 million of revenue subject to refund for estimated earnings above 12.5 percent in 2000 and 1999, respectively. Refunds applicable to 1999 were made to customers in 2000. The Company will file a general rate case on July 2, 2001 in response to which the GPSC would be expected to determine whether the retail rate order should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

Growth in energy sales is subject to a number of factors which traditionally have included changes in contracts with neighboring utilities, energy conservation practiced by customers, the elasticity of demand, weather, competition, initiatives to increase sales to existing customers, and the rate of economic growth in the Company's service area. Assuming normal weather, retail sales growth from 2000 is projected to be approximately 2.4 percent annually on average during 2001 through 2003.

The Company has entered into purchase power agreements which will result in higher capacity and operating and maintenance payments in future years. See Note 4 to the financial statements under "Purchased Power Commitments" for additional information.

The Company is constructing two 566 megawatt combined cycle units at Plant Wansley to begin operation in 2002. These units have been certified by the GPSC to serve the Company's retail customers for approximately seven years. Savannah Electric will have the rights to 200 megawatts of capacity from these units for the same seven-year period.

The Company is also constructing a 571 megawatt combined cycle unit at Plant Goat Rock to begin operation in 2002, and a 610 megawatt combined cycle unit at Plant Goat Rock to begin operation in 2003. The power from these units will initially be sold into the wholesale market when they begin operation. The Company has filed with the GPSC for certification of these units to begin serving the Company's retail customers in 2003 and 2004, respectively, for a term of seven years each.

In addition to seeking certification of Plant Goat Rock, the Company is also seeking certification of a seven year commitment to 615 megawatts beginning in 2004 at Plant Autaugaville to serve its retail customers. Plant Autaugaville is currently under construction by Alabama Power.

Further, the Company is constructing Plant Dahlberg, a ten unit, 800 megawatt combustion turbine peaking power plant that will serve the wholesale market. Units one through eight began operation in May 2000; units nine and ten are expected to begin operation in June 2001. The Company has entered into wholesale contracts to sell all 800 megawatts of capacity. These contracts cover substantially all of the output of the plant for the first five years. Because these units are dedicated to the wholesale market, retail rates will not be affected.

The Company is aggressively working to maintain and expand its share of wholesale sales in the Southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary, Southern Power Company (SPC). SPC will own, manage, and finance wholesale generating assets in the Southeast. Energy from its assets will be marketed to wholesale customers under the Southern Company name. The current plan is for Georgia Power and Alabama Power to transfer Plant Dahlberg and the units under construction at Plants Wansley, Goat Rock, and Autaugaville to SPC in 2001. The Company will enter into purchased power capacity agreements with SPC for power from the units at Plants Wansley, Goat Rock, and Autaugaville to serve the Company's retail customers.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $59 million in 2000. Pension plan income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan. For additional information see Note 2 to the financial statements.

Compliance costs related to current and future environmental laws, regulations, and litigation could affect earnings if such costs are not fully recovered. See "Environmental Issues" for further discussion of these matters.

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. Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. On October 16, 2000, Southern Company and its five integrated Southeast utilities, including the Company, filed with the FERC a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of participating utilities. Participants would have the option to either maintain their ownership, divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of the RTO is not expected to have a material impact on the financial statements of the Company. However, the ultimate outcome of this matter cannot now be determined.

The Company continues to compete with other electric suppliers within the state. In Georgia, most new retail customers with at least 900 kilowatts of connected load may choose their electricity supplier. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition across the nation. Among other things, these initiatives allow customers to choose their electricity provider. As these initiatives materialize, the structure of the utility industry could radically change. 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 the GPSC has held workshops to discuss retail competition and industry restructuring, there has been no proposed or enacted legislation to date in Georgia. Enactment would require numerous issues to be resolved, including significant ones relating to transmission pricing and recovery of costs. The GPSC continues its assessment of the range of potential stranded costs. The inability of the Company to recover all its costs, including the regulatory assets described in Note 1 to the financial statements, could have a material effect on the financial condition of the Company. The Company is attempting to reduce regulatory assets through the GPSC retail rate order. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

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 operations 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.

The staff of the Securities and Exchange Commission (SEC) has questioned certain of the current accounting practices of the electric utility industry - including the Company's - regarding the recognition, measurement, and classification in the financial statements of decommissioning costs for nuclear generating facilities. In response to these questions, the FASB is reviewing the accounting for liabilities related to the retirement of long-lived assets, including nuclear decommissioning. If the FASB issues new accounting rules, the estimated costs of retiring the Company's nuclear and other facilities may be required to be recorded as liabilities in the Balance Sheets. Also, the annual provisions for such costs could change. Because of the Company's current ability to recover asset retirement costs through rates, these changes would not have a significant adverse effect on results of operations. See Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning" for additional information.

Exposure to Market Risks

Due to cost-based rate regulation, the Company currently has limited exposure to market volatility in interest rates, commodity fuel prices and prices of electricity. (See the discussion above for potential changes in industry structure.) 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. Realized gains and losses are recognized in the income statement as incurred. At December 31, 2000, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. Also, based on the Company's overall interest rate exposure at December 31, 2000, a near-term 100 basis point change in interest rates would not materially affect the financial statements.

New Accounting Standard

In June 2000, the FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Substantially all of the Company's bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted the provisions of Statement No. 133 effective January 1, 2001. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from the FASB is expected, which could additionally impact the Company's financial statements.

FINANCIAL CONDITION

Plant Additions

In 2000, gross utility plant additions were $1.1 billion. These additions were primarily related to transmission and distribution facilities, the purchase of nuclear fuel, and the construction of additional combustion turbine and combined cycle units. The funds needed for gross property additions are currently provided from operations, short-term and long-term debt, and capital contributions from Southern Company. The Statements of Cash Flows provide additional details.

Financing Activities

In 2000, the Company's financing costs increased due to the issuance of new debt during the year. New issues during 1998 through 2000 totaled $1.5 billion and retirement or repayment of higher-cost securities totaled $1.7 billion.

Special purpose subsidiaries of the Company have issued mandatorily redeemable preferred securities. See Note 9 to the financial statements under "Preferred Securities" for additional information.

Composite financing rates for long-term debt, preferred stock, and preferred securities for the years 1998 through 2000, as of year-end, were as follows:

	2000	1999	1998
Composite interest rate on long-term debt	**5.90%**	5.48%	5.64%
Composite preferred stock dividend rate	**4.60**	4.60	5.52
Composite preferred securities dividend rate	**7.49**	7.49	7.89

Liquidity and Capital Requirements

Cash provided from operations decreased by $135 million in 2000, primarily due to higher fuel and purchased power expenses related to increased energy demands.

The Company estimates that construction expenditures for the years 2001 through 2003 will total $1.6 billion, $1.3 billion, and $0.8 billion, respectively. If the Company transfers wholesale generation assets to SPC in 2001 as contemplated, construction expenditures for the years 2001 through 2003 will total $1.0 billion, $0.9 billion, and $0.7 billion, respectively. Investments in additional combustion turbine and combined cycle generating units, transmission and distribution facilities, enhancements to existing generating plants, and equipment to comply with environmental requirements are planned.

Cash requirements for redemptions announced and maturities of long-term debt are expected to total $581 million during 2001 through 2003.

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. The amount to be funded is $30 million each year in 2001, 2002, and 2003. For additional information concerning nuclear decommissioning costs, see Note 1 to the financial statements under "Depreciation and Nuclear Decommissioning."

Sources of Capital

The Company expects to meet future capital requirements primarily using funds generated from operations and equity funds from Southern Company and, if needed, by the issuance of new debt and equity securities, term loans, and short-term borrowings. To meet short-term cash needs and contingencies, the Company had approximately $1.8 billion of unused credit arrangements with banks at the beginning of 2001. See Note 9 to the financial statements under "Bank Credit Arrangements" for additional information.

Recently, the Company has relied on the issuance of unsecured debt and trust preferred securities, in addition to unsecured pollution control bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. In years past, the Company issued first mortgage bonds, mortgage backed pollution control bonds and preferred stock to fund its external requirements. The amount outstanding of the later securities has been steadily declining during the last four years.

If the Company were to choose to issue new first mortgage bonds or preferred stock once again, it would be required to meet certain coverage requirements.

ENVIRONMENTAL ISSUES

Clean Air Act

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) were signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected Southern Company's subsidiaries, including the Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants are required in two phases. Phase I compliance began in 1995 and some 50 generating units within Southern Company's subsidiaries were brought into compliance with Phase I requirements.

Southern Company's subsidiaries, including the Company, achieved Phase I sulfur dioxide compliance at the affected units by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for the Company's Phase I compliance totaled approximately $167 million.

Phase II sulfur dioxide compliance was required in 2000. Southern Company's subsidiaries, including the Company, used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased total construction expenditures for the Company through 2000 by approximately $39 million.

The one-hour ozone non-attainment standards for the Atlanta area have been set and must be implemented in May 2003. Seven generating plants will be affected in the Atlanta area. Additional construction expenditures for the Company's compliance with these new rules are currently estimated at approximately $705 million.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

Environmental Protection Agency Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. 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 a notice of violation to the Company relating to these two plants. 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 equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. 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 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 unless such costs can be recovered through regulated rates.

Other Environmental Issues

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Georgia.

In December 2000, the EPA completed its utility study for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls would likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. Under these various laws and regulations, the Company could incur costs to clean up properties currently or previously owned. The Company conducts studies to determine the extent of any required clean-up costs and has recognized in the financial statements costs to clean up known sites. These costs for the Company amounted to $4 million, $4 million, and $6 million in 2000, 1999, and 1998, respectively. Additional sites may require environmental remediation for which the Company may be liable for a portion of or all required clean-up costs. See Note 3 to the financial statements under "Other Environmental Contingencies" for information regarding the Company's potentially responsible party status at a site in Brunswick, Georgia, and the status of sites listed on the State of Georgia's hazardous site inventory.

The EPA and state environmental regulatory agencies are reviewing and evaluating various matters including: control strategies to reduce regional haze; limits on pollutant discharges to impaired waters; water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electromagnetic fields.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The Company's 2000 Annual Report contains forward-looking and historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "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 and the race discrimination litigation against the Company; the extent and timing of the entry of additional competition in the Company's markets; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the Company; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998
Georgia Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$4,317,338**	$4,050,088	$4,298,217
Sales for resale --			
Non-affiliates	**297,643**	210,104	259,234
Affiliates	**96,150**	76,426	81,606
Other revenues	**159,487**	120,057	99,196
Total operating revenues	**4,870,618**	4,456,675	4,738,253
Operating Expenses:			
Operation --			
Fuel	**1,017,878**	919,876	917,119
Purchased power --			
Non-affiliates	**356,189**	214,573	229,960
Affiliates	**239,815**	174,989	161,003
Other	**795,458**	784,359	819,589
Maintenance	**404,189**	411,983	358,218
Depreciation and amortization	**619,094**	552,966	813,802
Taxes other than income taxes	**204,527**	202,853	204,623
Write down of Rocky Mountain plant	**-**	-	33,536
Total operating expenses	**3,637,150**	3,261,599	3,537,850
Operating Income	**1,233,468**	1,195,076	1,200,403
Other Income (Expense):			
Interest income	**2,629**	5,583	79,578
Equity in earnings of unconsolidated subsidiaries	**3,051**	2,721	3,735
Other, net	**(50,495)**	(47,986)	(38,277)
Earnings Before Interest and Income Taxes	**1,188,653**	1,155,394	1,245,439
Interest Charges and Other:			
Interest expense, net	**208,868**	194,869	216,313
Distributions on preferred securities of subsidiaries	**59,104**	65,774	54,327
Total interest charges and other, net	**267,972**	260,643	270,640
Earnings Before Income Taxes	**920,681**	894,751	974,799
Income taxes	**360,587**	351,639	398,632
Net Income	**560,094**	543,112	576,167
Dividends on Preferred Stock	**674**	1,729	5,939
Net Income After Dividends on Preferred Stock	**$ 559,420**	$ 541,383	$ 570,228

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Georgia Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	**$ 560,094**	$ 543,112	$ 576,167
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**712,960**	663,878	867,637
Deferred income taxes and investment tax credits, net	**(28,961)**	(34,930)	(93,005)
Other, net	**(51,501)**	(42,179)	40,396
Changes in certain current assets and liabilities --			
Receivables, net	**(108,621)**	21,665	(25,453)
Fossil fuel stock	**26,835**	(22,165)	(8,066)
Materials and supplies	**(9,715)**	(10,417)	(3,090)
Accounts payables	**64,412**	13,095	47,862
Energy cost recovery, retail	**(95,235)**	(26,862)	(7,649)
Other	**(9,092)**	90,788	6,997
Net cash provided from operating activities	**1,061,176**	1,195,985	1,401,796
Investing Activities:			
Gross property additions	**(1,078,163)**	(790,464)	(499,053)
Other	**(5,450)**	(27,454)	67,031
Net cash used for investing activities	**(1,083,613)**	(817,918)	(432,022)
Financing Activities:			
Increase (decrease) in notes payable, net	**67,598**	295,389	(25,378)
Proceeds --			
Senior notes	**300,000**	100,000	495,000
Pollution control bonds	**78,725**	238,000	89,990
Preferred securities	**-**	200,000	-
Capital contributions from parent company	**301,514**	155,777	235
Retirements --			
First mortgage bonds	**(100,000)**	(404,000)	(558,250)
Pollution control bonds	**(78,725)**	(235,000)	(89,990)
Preferred securities	**-**	(100,000)	-
Preferred stock	**(383)**	(36,231)	(106,064)
Capital distributions to parent company	**-**	-	(270,000)
Payment of preferred stock dividends	**(751)**	(984)	(9,137)
Payment of common stock dividends	**(549,600)**	(543,000)	(536,600)
Other	**(1,231)**	(29,630)	(26,641)
Net cash provided from (used for) financing activities	**17,147**	(359,679)	(1,036,835)
Net Change in Cash and Cash Equivalents	**(5,290)**	18,388	(67,061)
Cash and Cash Equivalents at Beginning of Year	**34,660**	16,272	83,333
Cash and Cash Equivalents at End of Year	**$ 29,370**	$ 34,660	$ 16,272
Supplemental Cash Flow Information:			
Cash paid during the year for --			
Interest (net of amount capitalized)	**$ 265,373**	$ 247,050	$ 269,524
Income taxes (net of refunds)	**392,310**	394,457	480,318

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Georgia Power Company 2000 Annual Report

Assets	**2000**	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 29,370**	$ 34,660
Receivables --		
Customer accounts receivable	**465,249**	401,773
Unrecovered retail fuel clause revenue	**131,623**	36,388
Other accounts and notes receivable	**156,143**	102,544
Affiliated companies	**13,312**	16,006
Accumulated provision for uncollectible accounts	**(5,100)**	(7,000)
Fossil fuel stock, at average cost	**99,463**	126,298
Materials and supplies, at average cost	**263,609**	253,894
Other	**97,515**	63,990
Total current assets	**1,251,184**	1,028,553
Property, Plant, and Equipment:		
In service	**16,469,706**	15,798,624
Less accumulated provision for depreciation	**6,914,512**	6,538,574
	9,555,194	9,260,050
Nuclear fuel, at amortized cost	**120,570**	119,288
Construction work in progress (Note 4)	**652,264**	425,975
Total property, plant, and equipment	**10,328,028**	9,805,313
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries (Note 4)	**25,485**	25,024
Nuclear decommissioning trusts	**375,666**	371,914
Other	**33,829**	33,766
Total other property and investments	**434,980**	430,704
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 8)	**565,982**	590,893
Prepaid pension costs	**205,113**	145,801
Debt expense, being amortized	**53,748**	55,824
Premium on reacquired debt, being amortized	**173,610**	184,331
Other	**120,964**	120,441
Total deferred charges and other assets	**1,119,417**	1,097,290
Total Assets	**$13,133,609**	$12,361,860

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Georgia Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	**2000**	1999
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 9)	**$ 1,808**	$ 155,772
Notes payable	**703,839**	636,241
Accounts payable --		
Affiliated	**117,168**	76,591
Other	**397,550**	346,785
Customer deposits	**78,540**	74,695
Taxes accrued --		
Income taxes	**5,151**	7,914
Other	**137,511**	127,414
Interest accrued	**47,244**	58,665
Vacation pay accrued	**38,865**	38,143
Other	**153,400**	153,767
Total current liabilities	**1,681,076**	1,675,987
Long-term debt (See accompanying statements)	**3,041,939**	2,688,358
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 8)	**2,182,783**	2,202,565
Deferred credits related to income taxes (Note 8)	**247,067**	267,083
Accumulated deferred investment tax credits (Note 8)	**352,282**	367,114
Employee benefits provisions	**177,444**	181,529
Other	**397,655**	236,812
Total deferred credits and other liabilities	**3,357,231**	3,255,103
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	**789,250**	789,250
Cumulative preferred stock (See accompanying statements)	**14,569**	14,952
Common stockholder's equity (See accompanying statements)	**4,249,544**	3,938,210
Total Liabilities and Stockholder's Equity	**$13,133,609**	$12,361,860

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Georgia Power Company 2000 Annual Report

		2000	1999	2000	1999
		(in thousands)		*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
March 1, 2000	6.00%	$ -	$ 100,000		
April 1, 2003	6.625%	**200,000**	200,000		
August 1, 2003	6.35%	**75,000**	75,000		
2005	6.07%	**10,000**	10,000		
2008	6.875%	**50,000**	50,000		
2025	7.70%	**57,000**	57,000		
Total first mortgage bonds		**392,000**	492,000		
Senior notes -- (Note 9)					
Variable rate (6.71375% at 1/1/01) due February 22, 2002		**300,000**	-		
5.50% due December 1, 2005		**150,000**	150,000		
6.60% due December 31, 2038		**200,000**	200,000		
6.625% due March 31, 2039		**100,000**	100,000		
6.875% due December 31, 2047		**145,000**	145,000		
Total senior notes payable		**895,000**	595,000		
Other long-term debt -- (Note 9)					
Pollution control revenue bonds --					
Maturity	Interest Rates				
2000	4.375%	-	50,000		
2005	5.00%	**57,000**	57,000		
2011	Variable (5.10% at 1/1/01)	**10,450**	10,450		
2018-2019	6.00% to 6.25%	**13,100**	13,100		
2021-2025	5.40% to 6.75%	**308,660**	337,385		
2022-2025	Variable (4.85% to 5.35% at 1/1/01)	**622,075**	622,075		
2026-2030	Variable (5.00% to 5.10% at 1/1/01)	**206,180**	206,180		
2030	4.53%	**78,725**	-		
2032-2034	Variable (5.0% to 5.30% at 1/1/01)	**140,000**	140,000		
2034	5.25% to 5.45%	**238,000**	238,000		
Total other long-term debt		**1,674,190**	1,674,190		
Capital lease obligations (Note 9)		**85,179**	85,851		
Unamortized debt discount, net		**(2,622)**	(2,911)		
Total long-term debt (annual interest requirement -- $179.6 million)		**3,043,747**	2,844,130		
Less amount due within one year (Note 9)		**1,808**	155,772		
Total long-term debt excluding amount due within one year		**$ 3,041,939**	$ 2,688,358	**37.6 %**	36.2 %

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2000 and 1999
Georgia Power Company 2000 Annual Report

	2000	1999	2000	1999
	(in thousands)		*(percent of total)*	
Company Obligated Mandatorily				
Redeemable Preferred Securities (Note 9):				
$25 liquidation value -- 6.85%	$ **200,000**	$ 200,000		
$25 liquidation value -- 7.60%	**175,000**	175,000		
$25 liquidation value -- 7.75%	**189,250**	189,250		
$25 liquidation value -- 7.75%	**225,000**	225,000		
Total (annual distribution requirement -- $59.1 million)	**789,250**	789,250	**9.7**	10.6
Cumulative Preferred Stock, without par value:				
Authorized -- 55,000,000 shares				
Outstanding -- 145,689 shares at December 31, 2000				
Outstanding -- 149,520 shares at December 31, 1999				
$100 stated value --				
4.60%	**14,569**	14,952		
Total cumulative preferred stock (annual dividend requirement -- $0.7 million)	**14,569**	14,952	**0.2**	0.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized -- 15,000,000 shares				
Outstanding -- 7,761,500 shares	**344,250**	344,250		
Paid-in capital	**2,117,497**	1,815,983		
Premium on preferred stock	**40**	40		
Retained earnings (Note 9)	**1,787,757**	1,777,937		
Total common stockholder's equity (See accompanying statements)	**4,249,544**	3,938,210	**52.5**	53.0
Total Capitalization	$ **8,095,302**	$ 7,430,770	**100.0 %**	100.0 %

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2000, 1999, and 1998
Georgia Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1998	$344,250	$1,929,971	$160	$1,745,347	$4,019,728
Net income after dividends on preferred stock	-	-	-	570,228	570,228
Capital distributions to parent company	-	(270,000)	-	-	(270,000)
Capital contributions from parent company	-	235	-	-	235
Cash dividends on common stock	-	-	-	(536,600)	(536,600)
Preferred stock transactions, net	-	-	(2)	583	581
Balance at December 31, 1998	344,250	1,660,206	158	1,779,558	3,784,172
Net income after dividends on preferred stock	-	-	-	541,383	541,383
Capital contributions from parent company	-	155,777	-	-	155,777
Cash dividends on common stock	-	-	-	(543,000)	(543,000)
Preferred stock transactions, net	-	-	(118)	(4)	(122)
Balance at December 31, 1999	344,250	1,815,983	40	1,777,937	3,938,210
Net income after dividends on preferred stock	-	-	-	**559,420**	**559,420**
Capital contributions from parent company	-	**301,514**	-	-	**301,514**
Cash dividends on common stock	-	-	-	**(549,600)**	**(549,600)**
Balance at December 31, 2000	**$344,250**	**$2,117,497**	**$40**	**$1,787,757**	**$4,249,544**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, Southern Company Services (SCS), the system service company, Southern Communications Services (Southern LINC), Mirant Corporation (formerly Southern Energy), Southern Nuclear Operating Company (Southern Nuclear), Southern Company Energy Solutions, and other direct and indirect subsidiaries. The integrated Southeast utilities (Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company) provide electric service in four states. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the subsidiary companies and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant Corporation acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant Corporation's businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the Southeastern United States.

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 Georgia Public Service Commission (GPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the 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 these estimates.

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

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, finance and treasury, tax, information resources, marketing, auditing, insurance and pension, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to \$269 million, \$253 million, and \$251 million during 2000, 1999, and 1998, respectively.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management and technical services; administrative services including procurement, accounting and statistical, employee relations, and systems and procedures services; strategic planning and budgeting services; and other services with respect to business and operations. Costs for these services amounted to \$281 million, \$270 million, and \$269 million during 2000, 1999, and 1998, respectively.

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. Pursuant to the terms of the GPSC retail rate order, the Company recorded \$135 million and \$85 million in 2000 and 1999, respectively, of accelerated cost recovery of regulatory assets which have been recorded on the balance sheet as a regulatory liability. See Note 3 under "Retail Rate Order" for additional information. Regulatory assets and (liabilities) reflected in the Company's Balance Sheets at December 31 relate to the following:

	2000	1999
	(in millions)	
Deferred income taxes	**$ 566**	$ 591
Deferred income tax credits	**(247)**	(267)
Premium on reacquired debt	**174**	184
Corporate building lease	**55**	54
Vacation pay	**49**	47
Postretirement benefits	**30**	33
Department of Energy assessments	**21**	24
Deferred nuclear outage costs	**28**	26
Accelerated cost recovery	**(220)**	(85)
Interest, accelerated cost recovery	**(10)**	-
Other, net	**23**	3
Total	**$ 469**	$ 610

In the event that a portion of the Company's operations is no longer subject to the provisions of 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 value.

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 Georgia, 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. The Company's fuel cost recovery mechanism includes provisions to adjust billings for fluctuations in fuel costs, 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 rates.

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 averaged 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 $75 million in 2000, $74 million in 1999, and $74 million in 1998. 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 contracts, and the Company is pursuing legal remedies against the government for breach of contract. Effective June 2000, the on-site dry storage facility for Plant Hatch became operational. Sufficient capacity is believed available to continue dry storage operations at Plant Hatch through the life of the plant. Sufficient fuel storage capacity currently is available at Plant Vogtle to maintain full-core discharge capability for both units into the year 2014.

Also, the Energy Policy Act of 1992 required the establishment of a Uranium Enrichment Decontamination and Decommissioning Fund, which is to be funded in part by a special assessment on utilities with nuclear plants. The assessment will be 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 -- based on its ownership interests -- estimates its remaining liability under this law at December 31, 2000 to be approximately $19 million. This obligation is recorded 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 3.3 percent in 2000 and 1999, and 3.2 percent in 1998. In addition, pursuant to a GPSC retail rate order, the Company recorded accelerated depreciation of electric plant of $304 million in 1998. Total accelerated depreciation recorded under the GPSC retail rate order was $467 million. These charges are recorded in the accumulated provision for depreciation. 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 costs of decommissioning nuclear facilities and removal of other facilities.

Nuclear Regulatory Commission (NRC) regulations require all licensees operating commercial 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 a set period of time as ordered by the GPSC. Earnings on the trust funds are considered in determining decommissioning expense. 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.

The Company periodically conducts site-specific studies to estimate the actual cost of decommissioning its nuclear generating facilities. 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 site study costs based on the most current study and ultimate costs assuming an inflation rate of 4.7 percent for the Company's ownership interests are as follows:

	Plant Hatch	Plant Vogtle
Site study basis (year)	2000	2000
Decommissioning periods:		
Beginning year	2014	2027
Completion year	2042	2045
	(in millions)	
Site study costs:		
Radiated structures	$486	$420
Non-radiated structures	37	48
Total	$523	$468
	(in millions)	
Ultimate costs:		
Radiated structures	$1,004	$1,468
Non-radiated structures	79	166
Total	$1,083	$1,634

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 the NRC requirements, changes in the assumptions used in making the estimates, changes in regulatory requirements, changes in technology, and changes in costs of labor, materials, and equipment. The Company has filed with the NRC an application requesting a 20-year renewal of the licenses for both units at Plant Hatch which would permit the operation of both units until 2034.

Annual provisions for nuclear decommissioning expense are based on an annuity method as approved by the GPSC. The amounts expensed in 2000 and fund balances as of December 31, 2000 were:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2000	$ 19	$ 9
	(in millions)	
Accumulated provisions:		
External trust funds, at fair value	$230	$146
Internal reserves	20	12
Total	$250	$158

Effective January 1, 1999, the GPSC increased the annual provision for decommissioning expenses to

$28 million from $20 million in 1998. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 1997 of $526 million and $438 million for Plants Hatch and Vogtle, respectively. The ultimate costs associated with the 1997 NRC minimum funding requirements are $1.1 billion and $1.3 billion for Plants Hatch and Vogtle, respectively. Significant assumptions include an estimated inflation rate of 3.6 percent and an estimated trust earnings rate of 6.5 percent. The Company expects the GPSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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)

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. For the years 2000, 1999, and 1998, the average AFUDC rates were 6.74 percent, 5.61 percent, and 6.71 percent, respectively. AFUDC, net of taxes, as a percentage of net income after dividends on preferred stock, was less than 2.0 percent for 2000, 1999 and 1998.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, less regulatory disallowances and impairments. Original cost includes: materials; labor; payroll-related costs such as taxes, pensions, and other benefits; and the cost of funds used during construction. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property (exclusive of minor items of property) is capitalized.

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.

Financial Instruments

The Company has a firm commitment that requires payment in euros. As a hedge against fluctuations in the exchange rate for euros, the Company entered into forward currency swaps. The notional amount is 15.9 million euros maturing in 2001 through 2002. At December 31, 2000, the unrecognized gain on these swaps was approximately $1.3 million.

The Company's financial instruments for which the carrying amounts did not approximate fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2000	**$2,959**	**$2,912**
At December 31, 1999	$2,758	$2,604
Preferred securities:		
At December 31, 2000	**$789**	**$761**
At December 31, 1999	$789	$680

The fair values for securities were based on either closing market prices or closing prices of comparable instruments.

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.

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed pension plans that cover substantially all employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all these employees may become eligible for such benefits when they retire. The Company funds postretirement trusts to the extent required by the GPSC and FERC. In late 2000, the Company adopted several pension and postretirement benefits plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits costs by approximately $10 million and $6 million, respectively. 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:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00**	5.00
Expected long-term return on plan assets	**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	
	2000	1999
	(in millions)	
Balance at beginning of year	**$1,205**	$1,217
Service cost	**32**	33
Interest cost	**88**	80
Benefits paid	**(58)**	(57)
Actuarial gain and employee transfers	**(14)**	(68)
Balance at end of year	**$1,253**	$1,205

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$2,107**	$1,859
Actual return on plan assets	**385**	313
Benefits paid	**(58)**	(57)
Employee transfers	**30**	(8)
Balance at end of year	**$2,464**	$2,107

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

	2000	1999
	(in millions)	
Funded status	**$1,211**	$ 902
Unrecognized transition obligation	**(26)**	(30)
Unrecognized prior service cost	**38**	41
Unrecognized net actuarial gain	**(1,018)**	(767)
Prepaid asset recognized in the Balance Sheets	**$ 205**	$ 146

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

	2000	1999	1998
	(in millions)		
Service cost	**$ 32**	$ 33	$ 30
Interest cost	**88**	80	82
Expected return on plan assets	**(151)**	(137)	(127)
Recognized net actuarial gain	**(27)**	(17)	(20)
Net amortization	**(1)**	(1)	(1)
Net pension income	**$ (59)**	$ (42)	$ (36)

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	
	2000	1999
	(in millions)	
Balance at beginning of year	**$438**	$464
Service cost	**7**	8
Interest cost	**36**	30
Benefits paid	**(21)**	(19)
Actuarial gain and employee transfers	**(28)**	(45)
Amendments	**63**	-
Balance at end of year	**$495**	$438

	Plan Assets	
	2000	1999
	(in millions)	
Balance at beginning of year	**$177**	$150
Actual return on plan assets	**12**	11
Employer contributions	**30**	35
Benefits paid	**(21)**	(19)
Balance at end of year	**$198**	$177

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

	2000	1999
	(in millions)	
Funded status	**$(297)**	$(261)
Unrecognized transition obligation	**113**	122
Unrecognized prior service cost	**60**	-
Unrecognized gain	**(13)**	-
Unrecognized net actuarial loss	**-**	10
Fourth quarter contributions	**27**	14
Accrued liability recognized in the Balance Sheets	**$(110)**	$(115)

Components of the plans' net periodic cost were as follows:

	2000	1999	1998
	(in millions)		
Service cost	**$ 7**	$ 8	$ 7
Interest cost	**36**	30	32
Expected return on plan assets	**(16)**	(10)	(9)
Recognized net actuarial loss	**-**	1	1
Net amortization	**12**	9	9
Net postretirement cost	**$ 39**	$38	$40

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005, 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$39	$ 34
Service and interest costs	3	3

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 2000, 1999, and 1998 were $15 million, $15 million, and $14 million, respectively.

3. CONTINGENCIES & REGULATORY MATTERS

Retail Rate Order

On December 18, 1998, the GPSC approved a three-year retail rate order for the Company ending December 31, 2001. Under the terms of the order, earnings are evaluated against a retail return on common equity range of 10 percent to 12.5 percent. Retail rates were decreased by $262 million on an annual basis effective January 1, 1999, and by an additional $24 million effective January 1, 2000. The order further provides for $85 million in each year, plus up to $50 million of any earnings above the 12.5 percent return during the second and third years, to be applied to accelerated amortization or depreciation of assets. Two-thirds of any additional earnings above the 12.5 percent return will be applied to rate reductions, with the remaining one-third retained by the Company. Pursuant to the order, in 2000 and 1999, the Company recorded $85 million each year in accelerated amortization of regulatory assets. In 2000, the Company also recorded the additional $50 million of accelerated amortization. The accelerated amortization is recorded in a regulatory liability account and, as mandated by the GPSC, the Company recorded $10 million of interest on the amounts in the regulatory liability account. In addition, the Company recorded $44 million and $79 million of revenue subject to refund for estimated earnings above 12.5 percent retail return on common equity in 2000 and 1999, respectively. Refunds applicable to 1999 were made to customers in 2000. The estimated 2000 refund is included in other current liabilities on the Balance Sheet. The Company will file a general rate case on July 2, 2001, in response to which the GPSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

Environmental Protection Agency (EPA) Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Bowen and Scherer plants. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units beginning at the point of the alleged violations. 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 a notice of violation to the Company relating to these two plants. 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 equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. 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 unless such costs can be recovered through regulated rates.

Other Environmental Contingencies

In January 1995, the Company and four other unrelated entities were notified by the EPA that they have been designated as potentially responsible parties under the Comprehensive Environmental Response, Compensation and Liability Act with respect to a site in Brunswick, Georgia. As of December 31, 2000, the Company has recognized approximately $5 million in cumulative expenses associated with the Company's agreed upon share of removal and remedial investigation and feasibility study costs for this site. The final outcome of this matter cannot now be determined. However, based on the nature and extent of the Company's activities relating to the site, management believes that the Company's portion of any remaining remediation costs should not be material to the financial statements.

In compliance with the Georgia Hazardous Site Response Act of 1993, the State of Georgia was required to compile an inventory of all known or suspected sites where hazardous wastes, constituents, or substances have been disposed of or released in quantities deemed reportable by the State. In developing this list, the State identified several hundred properties throughout the State, including 34 sites which may require environmental remediation that were either previously or are currently owned by the Company. The majority of these sites are electrical power substations and power generation facilities. The Company has remediated ten electrical substations on the list at a cumulative cost of approximately $3 million through December 31, 2000. The State has removed from the list three power generation facilities following the assessment which indicated no remediation was necessary. In addition, the Company has recognized approximately $27.5 million in cumulative expenses through December 31, 2000 for the assessment of the remaining sites on the list and the anticipated clean-up cost for 14 sites that the Company plans to remediate. Any additional costs of remediating the remaining sites cannot presently be determined until such studies are completed for each site and the State determines whether remediation is required. If all listed sites were required to be remediated, the Company could incur expenses of up to approximately $5 million in additional clean-up costs and construction expenditures of up to approximately $37 million to develop new waste management facilities or install additional pollution control devices.

Nuclear Performance Standards

The GPSC has adopted a nuclear performance standard for the Company's nuclear generating units under which the performance of Plants Hatch and Vogtle is evaluated every three years. The performance standard is based on each unit's capacity factor as compared to the average of all comparable U.S. nuclear units operating at a capacity factor of 50 percent or higher during the three-year period of evaluation. Depending on the performance of the units, the Company could receive a monetary award or penalty under the performance standards criteria.

In January 1997, the GPSC approved a performance award of approximately $11.7 million for performance during the 1993-1995 period. This award was collected through the retail fuel cost recovery provision and recognized in income over the 36-month period ending in December 1999. In February 2000, the GPSC approved a performance award of approximately $7.8 million for performance during the 1996-1998 period. This award is being collected through the retail fuel cost recovery provision and recognized in income over a 36-month period that began in January 2000, as mandated by the GPSC.

Race Discrimination Litigation

On July 28, 2000, a lawsuit alleging race discrimination was filed by three Georgia Power employees against the Company, Southern Company, and SCS in the United States District Court for the Northern District of Georgia. The lawsuit also raised claims on behalf of a purported class. The plaintiffs seek compensatory and punitive damages in an unspecified amount, as well as injunctive relief. On August 14, 2000, the lawsuit was amended to add four more plaintiffs and a new defendant, Southern Company Energy Solutions, Inc. The lawsuit is in the discovery stage. The final outcome of this case cannot now be determined.

4. COMMITMENTS

Construction Program

The Company is constructing Plant Dahlberg, a ten unit, 800 megawatt combustion turbine peaking power plant. Units one through eight began operation in May 2000; units nine and ten are expected to begin operation in June 2001. The Company is also constructing a 571 megawatt combined cycle unit and a 610 megawatt combined cycle unit at Plant Goat Rock that will begin operation in 2002 and in 2003, respectively, and an addition of two 566 megawatt combined cycle units at Plant Wansley, to begin operation in 2002. During 2001, the Company plans to transfer the units at Plants Dahlberg, Goat Rock, and Wansley at net book value to Southern Power Company (SPC), a new subsidiary formed by Southern Company. Significant construction of transmission and distribution facilities, and projects to upgrade and extend the useful life of generating plants and to remain in compliance with environmental requirements will continue. The Company currently estimates property additions to be approximately $1.6 billion in 2001, $1.3 billion in 2002, and $0.8 billion in 2003. If the Company transfers wholesale generation assets to SPC in 2001 as contemplated, construction expenditures for the years 2001 through 2003 will total $1.0 billion, $0.9 billion, and $0.7 billion, respectively.

The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors, including, but not limited to, changes in business conditions, load growth estimates, environmental regulations, and regulatory requirements.

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 fossil and nuclear fuel commitments at December 31, 2000 were as follows:

Year	Minimum Obligations
	(in millions)
2001	$1,006
2002	625
2003	586
2004	430
2005	342
2006 and beyond	873
Total minimum obligations	$3,862

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

Purchased Power Commitments

The Company and an affiliate, Alabama Power Company, 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, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power Company under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, 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 included in purchased power from affiliates in the Statements of Income is as follows:

	2000	1999	1998
	(in millions)		
Energy	**$57**	$51	$45
Capacity	**30**	29	30
Total	**$87**	$80	$75
Kilowatt-hours	**3,835**	3,338	3,146

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by Municipal Electric Authority of Georgia (MEAG) that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Except as noted below, the cost of such capacity and energy is included in purchased power from non-affiliates in the Company's Statements of Income. Capacity payments totaled $58 million, $57 million, and $56 million in 2000, 1999, and 1998, respectively. The current projected Plant Vogtle capacity payments are:

Year	Capacity Payments
	(in millions)
2001	$ 59
2002	58
2003	58
2004	55
2005	55
2006 and beyond	539
Total capacity payments	$824

Portions of the payments noted above relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions was written off in 1987 and 1990.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations at December 31, 2000 were as follows:

Year	Other Obligations
	(in millions)
2001	$ 22
2002	39
2003	41
2004	40
2005	40
2006 and beyond	154
Total other obligations	$336

Operating Leases

The Company has entered into coal rail car rental agreements with various terms and expiration dates. These expenses totaled $16 million for 2000, $11 million for 1999, and $13 million for 1998. At December 31, 2000, estimated minimum rental commitments for these noncancelable operating leases were as follows:

Year	Minimum Obligations
	(in millions)
2001	$ 15
2002	15
2003	15
2004	16
2005	14
2006 and beyond	102
Total minimum obligations	$177

5. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988, 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 the Company's nuclear power plants. The Act provides funds up to $9.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $200 million by private insurance, with the remaining coverage provided by a mandatory program of deferred premiums that 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 for the Company, excluding any applicable state premium taxes -- based on its ownership and buyback interests -- is $178 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 costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can be insured against increased costs of replacement power in an amount up to $3.5 million per week -- starting 12 weeks after the outage -- for one year and up to $2.8 million per week for the second and third years.

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 $19 million.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies should 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.

6. JOINT OWNERSHIP AGREEMENTS

Except as otherwise noted, the Company has contracted to operate and maintain all jointly owned generating facilities. The Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with Oglethorpe Power Company who is the operator of the plant. The Company also jointly owns Plant McIntosh with Savannah Electric and Power Company who operates the plant. The Company and Florida Power Corporation (FPC) jointly own a combustion turbine unit (Intercession City) operated by FPC.

The Company includes its proportionate share of plant operating expenses in the corresponding operating expenses in the Statements of Income.

At December 31, 2000, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,301*	$1,724
Plant Hatch (nuclear)	50.1	873	650
Plant Wansley (coal)	53.5	300	150
Plant Scherer (coal)			
Units 1 and 2	8.4	112	53
Unit 3	75.0	545	207
Plant McIntosh			
Common Facilities (combustion-turbine)	75.0	19	2
Rocky Mountain (pumped storage)	25.4	169*	72
Intercession City (combustion-turbine)	33.3	11	1

* Investment net of write-offs.

7. LONG-TERM POWER SALES AND LEASE AGREEMENTS

The Company and the other integrated Southeast utilities of Southern Company have long-term contractual agreements for the sale of capacity and energy to non-affiliated utilities located outside the system's service area. These agreements consist of firm unit power sales pertaining to capacity from specific generating units. Because energy is generally sold at cost under these agreements, it is primarily the capacity revenues that affect the Company's profitability.

The Company's capacity revenues were as follows:

Year	Revenues	Capacity
	(in millions)	(megawatts)
2000	**$ 30**	**124**
1999	32	162
1998	32	162

Unit power from specific generating plants is being sold to Florida Power & Light Company, FPC, and Jacksonville Electric Authority. Under these agreements, approximately 102 megawatts of capacity is scheduled to be sold annually for periods after 2000 with a minimum of three years notice until the expiration of the contracts in 2010.

During 2000, the Company entered into certain operating leases for portions of its generating unit capacity. Minimum future capacity revenues from noncancelable operating leases as of December 31, 2000 were as follows:

Year	Minimum Obligations
	(in millions)
2001	$ 41
2002	45
2003	45
2004	45
2005	5
2006 and beyond	-
Total minimum obligations	$181

8. INCOME TAXES

At December 31, 2000, tax-related regulatory assets were $566 million and tax-related regulatory liabilities were $247 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The 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 federal and state income tax provisions are as follows:

	2000	1999	1998
Total provision for income taxes:		(in millions)	
Federal:			
Current	**$342**	$333	$415
Deferred	**(34)**	(34)	(87)
Deferred investment tax credits	**-**	-	7
	308	299	335
State:			
Current	**48**	54	77
Deferred	**(5)**	(6)	(13)
Deferred investment tax credits	**10**	5	-
Total	**$361**	$352	$399

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:

	2000	1999
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,755**	$1,766
Property basis differences	**683**	729
Other	**243**	155
Total	**2,681**	2,650
Deferred tax assets:		
Other property basis differences	**189**	200
Federal effect of state deferred taxes	**91**	93
Other deferred costs	**208**	109
Other	**37**	48
Total	**525**	450
Net deferred tax liabilities	**2,156**	2,200
Portion included in current assets	**27**	3
Accumulated deferred income taxes in the Balance Sheets	**$2,183**	$2,203

Deferred investment tax credits are amortized over the life 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 $15 million in 2000 and 1999, and $22 million in 1998. At December 31, 2000, all investment tax credits available to reduce federal income taxes payable had been utilized.

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

	2000	1999	1998
Federal statutory rate	**35%**	35%	35%
State income tax, net of federal deduction	**4**	4	4
Non-deductible book depreciation	**2**	2	6
Other	**(2)**	(2)	(4)
Effective income tax rate	**39%**	39%	41%

Southern Company and its subsidiaries file 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.

9. CAPITALIZATION

First Mortgage Bond Indenture Restrictions

The Company's first mortgage bond indenture contains various restrictions that remain in effect as long as the bonds are outstanding. At December 31, 2000, $891 million of retained earnings and paid-in capital was unrestricted for the payment of cash dividends or any other distributions under terms of the mortgage indenture. If additional first mortgage bonds are issued, supplemental indentures in connection with those issues may contain more stringent restrictions than those currently in effect. The Company has no restrictions on the amount of indebtedness it may incur.

Preferred Securities

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

	Date of Issue	Amount (millions)	Rate	Notes (millions)	Maturity Date
Trust I	8/1996	$225.00	7.75%	$232	6/2036
Trust II	1/1997	175.00	7.60	180	12/2036
Trust III	6/1997	189.25	7.75	195	3/2037
Trust IV	2/1999	200.00	6.85	206	3/2029

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.

Pollution Control Bonds

The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The Company has authenticated and delivered to trustees an aggregate of $378.8 million of its first mortgage bonds outstanding at December 31, 2000, which are pledged as security for its obligations under pollution control revenue contracts. No interest on these first mortgage bonds is payable unless and until a default occurs on the installment purchase or loan agreements.

Senior Notes

In February 2000 and February 2001, the Company issued unsecured senior notes. The proceeds of these issues were used to redeem higher cost long-term debt and to reduce short-term borrowing. The senior notes are, in effect, subordinated to all secured debt of the Company, including its first mortgage bonds.

Bank Credit Arrangements

At the beginning of 2001, the Company had unused credit arrangements with banks totaling $1.8 billion, of which $1.3 billion expires at various times during 2001, and $500 million expires at April 24, 2003.

Of the total $1.8 billion in unused credit, $1.65 billion is a syndicated credit arrangement with $1.15 billion expiring April 20, 2001, and $500 million expiring April 24, 2003. Upon expiration, the $1.15 billion agreement provides the option of converting borrowings into two-year term loans. Both agreements contain stated borrowing rates but also allow for competitive bid loans.

In addition, the agreements require payment of commitment fees based on the unused portions of the commitments. Annual fees are also paid to the agent bank.

Approximately $115 million of the $1.3 billion arrangements expiring during 2001 allow for two-year term loans executable upon the expiration date of the facilities. All of the arrangements include stated borrowing rates but also allow for negotiated rates. These agreements also require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. These balances are not legally restricted from withdrawal.

This $1.8 billion in unused credit arrangements provides liquidity support to the Company's variable rate pollution control bonds. The amount of variable rate pollution control bonds outstanding requiring that liquidity support as of December 31, 2000 was $979 million.

In addition, the Company borrows under uncommitted lines of credit with banks and through a $750 million commercial paper program that has the liquidity support of committed bank credit arrangements. Average compensating balances held under these committed facilities were not material in 2000.

Other Long-Term Debt

Assets acquired under capital leases are recorded in the Balance Sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2000 and 1999, the Company had a capitalized lease obligation for its corporate headquarters building of $87 million with an interest rate of 8.1 percent. The lease agreement provides for payments that are minimal in early years and escalate through the first 21 years of the lease. For ratemaking purposes, the GPSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes is being deferred as a cost to be recovered in the future as ordered by the GPSC. At December 31, 2000 and 1999, the interest and lease amortization deferred on the Balance Sheets are $55 million and $54 million, respectively.

Assets Subject to Lien

The Company's mortgage dated as of March 1, 1941, 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.

Securities Due Within One Year

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

	2000	1999
	(in millions)	
Bond improvement fund requirements	**$ -**	$ 5
Capital lease – current portion	**2**	1
First mortgage bond maturities and redemptions	**-**	100
Pollution control bond maturities and redemptions	**-**	50
Total long-term debt	**$2**	$156

The Company's first mortgage bond indenture includes an improvement fund requirement that amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control obligations. The requirement may be satisfied by June 1 of each year by depositing cash, reacquiring bonds, or by pledging additional property equal to 1 2/3 times the requirement.

Redemption of Securities

The Company plans to continue, to the extent possible, a program of redeeming or replacing debt and preferred securities in cases where opportunities exist to reduce financing costs. Issues may be repurchased in the open market or called at premiums as specified under terms of the issue. They may also be redeemed at face value to meet improvement fund requirements, to meet replacement provisions of the mortgage, or through use of proceeds from the sale of property pledged under the mortgage.

10. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial information for 2000 and 1999 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2000	**$ 992**	**$223**	**$ 94**
June 2000	**1,221**	**311**	**148**
September 2000	**1,545**	**537**	**283**
December 2000	**1,113**	**162**	**34**
March 1999	$ 931	$224	$ 92
June 1999	1,092	299	138
September 1999	1,466	557	296
December 1999	968	115	15

Under the GPSC retail rate order, the Company recorded $135 million and $85 million of accelerated amortization in 2000 and 1999, respectively, which were recorded monthly as an operating expense. The fourth quarter December 1999 operating income has been restated to reflect the accelerated amortization as an operating expense rather than as amortization of premium on reacquired debt. See Note 3 to the financial statements under "Retail Rate Order" for additional information.

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

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SELECTED FINANCIAL AND OPERATING DATA 1996-2000
Georgia Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)	**$4,870,618**	$4,456,675	$4,738,253	$4,385,717	$4,416,779
Net Income after Dividends on Preferred Stock (in thousands)	**$559,420**	$541,383	$570,228	$593,996	$580,327
Cash Dividends on Common Stock (in thousands)	**$549,600**	$543,000	$536,600	$520,000	$475,500
Return on Average Common Equity (percent)	**13.66**	14.02	14.61	14.53	13.73
Total Assets (in thousands)	**$13,133,609**	$12,361,860	$12,033,618	$12,573,728	$13,006,635
Gross Property Additions (in thousands)	**$1,078,163**	$790,464	$499,053	$475,921	$428,220
Capitalization (in thousands):					
Common stockholder's equity	**$4,249,544**	$3,938,210	$3,784,172	$4,019,728	$4,154,281
Preferred stock	**14,569**	14,952	15,527	157,247	464,611
Company obligated mandatorily redeemable preferred securities	**789,250**	789,250	689,250	689,250	325,000
Long-term debt	**3,041,939**	2,688,358	2,744,362	2,982,835	3,200,419
Total (excluding amounts due within one year)	**$8,095,302**	$7,430,770	$7,233,311	$7,849,060	$8,144,311
Capitalization Ratios (percent):					
Common stockholder's equity	**52.5**	53.0	52.3	51.2	51.0
Preferred stock	**0.2**	0.2	0.2	2.0	5.7
Company obligated mandatorily redeemable preferred securities	**9.7**	10.6	9.5	8.8	4.0
Long-term debt	**37.6**	36.2	38.0	38.0	39.3
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	**AA-**	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	A-	A	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	**1,669,566**	1,632,450	1,596,488	1,561,675	1,531,453
Commercial	**237,977**	229,524	221,180	211,672	205,087
Industrial	**8,533**	8,958	9,485	9,988	10,424
Other	**3,159**	3,060	3,034	2,748	2,645
Total	**1,919,235**	1,873,992	1,830,187	1,786,083	1,749,609
Employees (year-end):	**8,855**	8,961	8,371	8,354	10,346

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Georgia Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands):					
Residential	**$ 1,535,684**	$1,410,099	$ 1,486,699	$ 1,326,787	$ 1,371,033
Commercial	**1,620,466**	1,527,880	1,591,363	1,493,353	1,486,586
Industrial	**1,154,789**	1,143,001	1,170,881	1,110,311	1,118,633
Other	**6,399**	(30,892)	49,274	47,848	47,060
Total retail	**4,317,338**	4,050,088	4,298,217	3,978,299	4,023,312
Sales for resale - non-affiliates	**297,643**	210,104	259,234	282,365	281,580
Sales for resale - affiliates	**96,150**	76,426	81,606	38,708	35,886
Total revenues from sales of electricity	**4,711,131**	4,336,618	4,639,057	4,299,372	4,340,778
Other revenues	**159,487**	120,057	99,196	86,345	76,001
Total	**$4,870,618**	$4,456,675	$4,738,253	$4,385,717	$4,416,779
Kilowatt-Hour Sales (in thousands):					
Residential	**20,693,481**	19,404,709	19,481,486	17,295,022	17,826,451
Commercial	**25,628,402**	23,715,485	22,861,391	21,134,346	20,823,073
Industrial	**27,543,265**	27,300,355	27,283,147	26,701,685	26,191,831
Other	**568,906**	551,451	543,462	538,163	536,057
Total retail	**74,434,054**	70,972,000	70,169,486	65,669,216	65,377,412
Sales for resale - non-affiliates	**6,463,723**	5,060,931	6,438,891	6,795,300	7,868,342
Sales for resale - affiliates	**2,435,106**	1,795,243	2,038,400	1,706,699	1,180,207
Total	**83,332,883**	77,828,174	78,646,777	74,171,215	74,425,961
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.42**	7.27	7.63	7.67	7.69
Commercial	**6.32**	6.44	6.96	7.07	7.14
Industrial	**4.19**	4.19	4.29	4.16	4.27
Total retail	**5.80**	5.71	6.13	6.06	6.15
Sales for resale	**4.43**	4.18	4.02	3.78	3.51
Total sales	**5.65**	5.57	5.90	5.80	5.83
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,520**	12,006	12,314	11,171	11,763
Residential Average Annual Revenue Per Customer	**$929.11**	$872.47	$939.73	$857.01	$904.70
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,114**	14,474	14,437	14,437	14,367
Maximum Peak-Hour Demand (megawatts):					
Winter	**12,014**	11,568	11,959	10,407	10,410
Summer	**14,930**	14,575	13,923	13,153	12,914
Annual Load Factor (percent)	**61.6**	58.9	58.7	57.4	62.2
Plant Availability (percent):					
Fossil-steam	**86.1**	84.3	86.0	85.8	85.2
Nuclear	**91.5**	89.3	91.6	88.8	89.3
Source of Energy Supply (percent):					
Coal	**62.3**	63.0	62.3	64.3	60.4
Nuclear	**17.4**	18.0	18.3	18.8	18.2
Hydro	**0.7**	0.9	2.2	2.2	2.2
Oil and gas	**1.8**	1.6	2.2	0.6	0.5
Purchased power -					
From non-affiliates	**8.1**	6.6	6.5	2.7	5.6
From affiliates	**9.7**	9.9	8.5	11.4	13.1
Total	**100.0**	100.0	100.0	100.0	100.0

GULF POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT
Gulf Power Company 2000 Annual Report

The management of Gulf 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 audit committee of the board of directors, composed of independent directors provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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 Gulf Power Company in conformity with accounting principles generally accepted in the United States.

Travis J. Bowden
President
and Chief Executive Officer

Ronnie R. Labrato
Comptroller
and Chief Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Gulf Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (a Maine corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2000 and 1999, 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, 2000. 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 II-123 through II-137) referred to above present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Gulf Power Company's 2000 net income after dividends on preferred stock was $51.8 million, a decrease of $1.9 million from the previous year. In 1999, earnings were $53.7 million, down $2.8 million when compared to 1998. The decrease in earnings in 2000, as well as 1999, was primarily a result of higher expenses than in the prior year.

Revenues

Operating revenues increased in 2000 when compared to 1999. The following table summarizes the change in operating revenues for the past two years:

	Amount	Increase (Decrease) From Prior Year	
	2000	2000	1999
	(in thousands)		
Retail --			
Base Revenues	$336,103	$3,771	$2,469
Regulatory cost recovery and other	226,059	45,631	1,173
Total retail	562,162	49,402	3,642
Sales for resale--			
Non-affiliates	66,890	4,537	461
Affiliates	66,995	885	23,468
Total sales for resale	133,885	5,422	23,929
Other operating revenues	18,272	(14,604)	(3,990)
Total operating revenues	$714,319	$40,220	$23,581
Percent change		6.0%	3.6%

Retail revenues of $562.2 million in 2000 increased $49.4 million, or 9.6 percent, from the prior year due primarily to the recovery of higher fuel and purchased power costs. Retail base rate revenues increased $3.8 million due to increased customer growth and hotter than normal weather, offset by a $10 million permanent annual rate reduction and $6.9 million of revenues subject to refund based upon the current retail revenue sharing plan (See Note 3 to the financial statements under "Retail Revenue Sharing Plan" for further information). Retail revenues for 1999 increased $3.6 million, or 0.7 percent, when compared to 1998 due primarily to an increase in the number of retail customers served by the Company.

The 2000 increase in regulatory cost recovery and other retail revenues over 1999 is primarily attributable to higher fuel and purchased power costs. The 1999 increase in regulatory cost recovery and other retail revenues over 1998 is primarily attributable to the recovery of increased purchased power capacity costs. "Regulatory cost recovery and other" includes the following: recovery provisions for fuel expense and the energy component of purchased power costs; energy conservation costs; purchased power capacity costs; and environmental compliance costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further information.

Sales for resale were $133.9 million in 2000, an increase of $5.4 million, or 4.2 percent, over 1999 primarily due to additional energy sales. Revenues from sales to utilities outside the service area under long-term contracts consist of capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components under these long-term contracts were as follows:

	2000	1999	1998
	(in thousands)		
Capacity	$20,270	$19,792	$22,503
Energy	21,922	20,251	14,556
Total	$42,192	$40,043	$37,059

Capacity revenues increased slightly in 2000 due to the recovery of higher operating expenses experienced during the year. Capacity revenues had been declining in prior years due to the decreasing net investment related to these sales. This downward trend accelerated during 1999 as a result of a reduction in the authorized rate of return on the equity component of the investment.

Sales to affiliated companies vary from year to year depending on demand and the availability and cost of generating resources at each company. These sales have little impact on earnings.

Other operating revenues decreased in 2000 and in 1999 due primarily to the retail recovery clause adjustments for the difference between recoverable costs and the amounts actually reflected in current rates. See Notes 1 and 3 to the financial statements under "Revenues and Regulatory Cost Recovery Clauses" and "Environmental Cost Recovery," respectively, for further discussion.

Energy Sales

Kilowatt-hour sales for 2000 and the percent changes by year were as follows:

	KWH	Percent Change	
	2000	2000	1999
	(millions)		
Residential	4,790	7.1%	0.8%
Commercial	3,379	4.9	3.6
Industrial	1,925	4.3	0.7
Other	19	0.0	0.0
Total retail	10,113	5.8	1.7
Sales for resale			
Non-affiliates	1,705	9.2	16.4
Affiliates	1,917	(23.7)	42.9
Total	13,735	0.7	9.0

In 2000, total retail energy sales increased when compared to 1999 due primarily to an increase in the total number of customers and hotter than normal weather. Total retail energy sales increased in 1999 when compared to 1998 due to increases in the number of customers. See "Future Earnings Potential" for information on the Company's initiatives to remain competitive and to meet conservation goals set by the Florida Public Service Commission (FPSC).

An increase in energy sales for resale to non-affiliates of 9.2 percent in 2000 when compared to 1999 is primarily related to unit power sales under long-term contracts to other Florida utilities and bulk power sales under short-term contracts to other non-affiliated utilities. Energy sales to affiliated companies vary from year to year depending on demand and availability and cost of generating resources at each company.

Expenses

Total operating expenses in 2000 increased $39.5 million, or 7.1 percent, over the amount recorded in 1999 due primarily to higher fuel and purchased power expenses. In 1999, total operating expenses increased $26.8 million, or 5.1 percent, compared to 1998 due primarily to higher fuel, purchased power, and maintenance expenses offset by lower other operation expenses.

Fuel expenses in 2000, when compared to 1999, increased $6.7 million, or 3.2 percent, due primarily to an increase in average fuel costs. In 1999, fuel expenses increased $11.5 million, or 5.9 percent, when compared to 1998. The increases were the result of increased generation resulting from a higher demand for energy.

The amount and sources of generation and the average cost of fuel per net kilowatt-hour generated were as follows:

	2000	1999	1998
Total generation (millions of kilowatt-hours)	12,866	13,095	11,986
Sources of generation (percent)			
Coal	98.2	97.4	98.0
Oil and gas	1.8	2.6	2.0
Average cost of fuel per net kilowatt-hour generated (cents)--	1.68	1.60	1.69

Purchased power expenses increased in 2000 by $25.5 million, or 44.7 percent, over 1999 and purchased power expenses for 1999 increased over 1998 by $13.2 million, or 30.2 percent, due primarily to a higher demand for energy in both years.

Depreciation and amortization expense increased $2.3 million, or 3.5 percent, in 2000 when compared to 1999, due to an increase in depreciable property and the amortization of a portion of a regulatory asset, which was allowed in the current retail revenue sharing plan. The $5.5 million, or 9.2 percent, increase in 1999 compared to 1998 was due primarily to a reduction in the amortization of gains from the 1998 sale of emission allowances.

Interest on long-term debt, which is included in "Interest expense", increased $1.2 million, or 5.8 percent, in 2000 when compared to 1999 due primarily to the issuance of $50 million of senior notes in August 1999. In 1999 interest on long-term debt increased $1.7 million, or 8.4 percent, when compared to 1998 due primarily to the maturity of two first mortgage bond series in 1998 which were replaced by senior notes at a slightly higher interest rate, and the issuance of $50 million of senior notes in August 1999.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of historical costs. Therefore, inflation creates an economic loss because the Company is recovering its cost 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.

Future Earnings Potential

The results of 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 to achieve energy sales growth while containing cost in a more competitive environment.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $5.8 million in 2000. Pension income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in northwest Florida. Prices for electricity provided by the Company to retail customers are set by the FPSC.

Future earnings in the near term will depend upon growth in energy sales, which is subject to a number of factors. Traditionally, these factors have included weather, competition, changes in 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. In early 1999, the FPSC staff and the Company became involved in discussions primarily related to reducing the Company's authorized rate of return. On October 1, 1999, the Office of Public Counsel, the Coalition for Equitable Rates, the Florida Industrial Power Users Group, and the Company jointly filed a petition to resolve the issues. The stipulation included a reduction to retail base rates of $10 million annually and provides for revenues to be shared within set ranges for 1999 through 2002. Customers receive two-thirds of any revenue within the sharing range and the Company retains one-third. Any revenue above this range is refunded to the customers. The stipulation also included authorization for the Company, at its discretion, to accrue up to an additional $5 million to the property insurance reserve and $1 million to amortize a regulatory asset related to the corporate office. The Company also filed a request to prospectively reduce its authorized ROE range from 11 to 13 percent to 10.5 to 12.5 percent in order to help ensure that the FPSC would approve the stipulation. The FPSC approved both the stipulation and the ROE request with an effective date of November 4, 1999. The Company is currently planning to seek additional rate relief to recover costs related to the Smith Unit 3 combined cycle facility currently under construction and scheduled to be placed in-service in June of 2002.

For calendar year 2000, the Company's retail revenue range for sharing was $352 million to $368 million. Actual retail revenues in 2000 were $362.4 million and the Company recorded revenues subject to refund of $6.9 million. The estimated refund with interest was reflected in customer billings in February 2001. For calendar year 2001, the Company's retail revenue range for sharing is $358 million to $374 million. For calendar year 2002, there are specified sharing ranges for each month from the expected in-service date of Smith Unit 3 until the end of the year. The sharing plan will expire at the earlier of the in-service date of Smith Unit 3 or December 31, 2002.

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 cogeneration plants for a utility's large industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are being driven down by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers. The Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets.

In 2000, Florida's Governor appointed a 17 member study commission to look at the state's electric industry, studying issues ranging from current and future reliability of electric and natural gas supply, electric industry retail and wholesale competition, environmental impacts of energy supply, conservation, and tax issues. The commission's final report and recommendations are due to the Governor and legislature by December 1, 2001. The commission submitted an interim report to the state legislature that involves introducing more competition into the wholesale production of electricity in Florida. If approved by the legislature, the proposal would require utilities to turn over generating assets to an unregulated affiliate company over a 6-year transition period. The proposal would allow out of state companies to build merchant facilities and to bid on new generation needs. The effects of any proposed changes cannot presently be determined, but could have a material effect on the Company's financial statements.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers 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 Florida, none have been enacted. Enactment 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 current energy crisis in California. As a result of this crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation. The inability of a company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on financial condition and results of operations.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. 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.

In 1996, the FPSC approved a new optional Commercial/Industrial Service Rider (CISR), which is applicable to the rate schedules for the Company's largest existing and potential customers who are able to show they have viable alternatives to purchasing the Company's energy services. The CISR, approved as a pilot program, provides the flexibility needed to enable the Company to offer its services in a more competitive manner to these customers. The publicity of the CISR ruling, increased competitive pressures, and general awareness of customer choice pilots and proposals across the country have stimulated interest on the part of customers in custom tailored offerings. The Company has participated in one-on-one discussions with many of these customers, and has negotiated and executed two Contract Service Agreements within the CISR pilot program. The pilot program was scheduled to end in 2000; however, on February 6, 2001 the FPSC approved the Company's request to remove the original 48 month limitation and allow the program to continue.

Every five years the FPSC establishes numeric demand side management goals. The Company proposed numeric goals for the ten-year period from 2000 to 2009. The proposed goals consisted of the total, cost-effective winter and summer peak demand (kilowatts) and annual energy (kilowatt-hour) savings reasonably achievable from demand side management for the residential and commercial/industrial classes. The Company submitted its 2001 Demand Side Management Plan to the FPSC on December 29, 2000. The plan describes the proposed programs the Company will employ to reach the numeric goals. The plan relies heavily on innovative pricing and energy efficient construction.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. Southern Company and its integrated utility subsidiaries, including the Company, filed on October 16, 2000, a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of the Company and any other participating utilities. Participants would have the option to either maintain their ownership or divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on the Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUHCA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUHCA. These entities are able to own and operate power generating facilities and sell power to affiliates -- under certain restrictions.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary -- Southern Power Company. The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. Southern Power will be the primary growth engine for Southern Company's market-based energy business. Energy from its assets will be marketed to wholesale customers under the Southern Company name.

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." Also, Florida legislation adopted in 1993 that provides for recovery of prudent environmental compliance costs is discussed in Note 3 to the financial statements under "Environmental Cost Recovery."

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 operations 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.

Exposure to Market Risks

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates 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. Realized gains and losses are recognized in the income statements as incurred. At December 31, 2000, exposure from these activities was not material.

New Accounting Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

The Company may utilize financial instruments to reduce its exposure to changes in interest rates depending on market conditions. The Company also enters into commodity related forward contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales.

Substantially all of these bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted Statement No. 133 effective January 1, 2001. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from FASB is expected, which could additionally impact the Company's financial statements. Also, as wholesale energy markets mature, future transactions could result in more volatility in net income and comprehensive income.

Financial Condition

Overview

The Company's financial condition continues to be very solid. During 2000, gross property additions were $95.8 million. Funds for the property additions were provided by operating activities. See the Statements of Cash Flows for further details.

Financing Activities

In 2000, there were no issuances or retirements of long-term debt. In 1999, the Company sold $50 million of senior notes and long-term bank notes totaling $27 million were retired. See the Statements of Cash Flows for further details.

Composite financing rates for the years 1998 through 2000 as of year end were as follows:

	2000	1999	1998
Composite interest rate on long-term debt	**6.2%**	6.0%	6.1%
Composite rate on trust preferred securities	**7.3%**	7.3%	7.3%
Composite preferred stock dividend rate	**5.1%**	5.1%	5.1%

The composite interest rate on long-term debt increased in 2000 due to higher interest rates on variable rate pollution control bonds.

Capital Requirements for Construction

The Company's gross property additions, including those amounts related to environmental compliance, are budgeted at $451 million for the three years beginning in 2001 ($279 million in 2001, $96 million in 2002, and $76 million in 2003). These amounts include $199.2 million for the years 2001 and 2002 for the estimated cost of a 574 megawatt combined cycle gas generating unit and related interconnections to be located in the eastern portion of the Company's service area. The unit is expected to have an in-service date of June 2002. The remaining property additions budget is primarily for maintaining and upgrading transmission and distribution facilities and generating plants. Actual construction costs may vary from this estimate because of changes in such factors as the following: business conditions; environmental 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

The Company will continue to retire higher-cost debt and preferred securities and replace these securities with lower-cost capital as market conditions and terms of the instruments permit.

Environmental Matters

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) was signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected the Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995. As a result of a systemwide compliance strategy, some 50 generating units of Southern Company were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions compliance totaled approximately $300 million for Southern Company, including approximately $42 million for the Company.

Phase II sulfur dioxide compliance was required in 2000. Southern Company used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased Southern Company's total construction expenditures through 2000 by approximately $100 million. Phase II compliance did not have a material impact on Gulf Power.

A significant portion of costs related to the acid rain and ozone nonattainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In 1993, the Florida Legislature adopted legislation that allows a utility to petition the FPSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the Environmental Cost Recovery Clause.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rule to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Georgia. See Note 5 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3.

In December 2000, the EPA completed its utility study for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls will likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are also reviewing and evaluating various other matters including: nitrogen oxide emission control strategies for ozone non-attainment areas; additional controls for hazardous air pollutant emissions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

On November 3, 1999, the EPA brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 5 to the financial statements under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in

Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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 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.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. 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 costs and has recognized in the financial statements costs to clean up known sites. For additional information, see Note 3 to the financial statements under "Environmental Cost Recovery."

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electric and magnetic fields, and other environmental health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electric and magnetic fields.

Sources of Capital

At December 31, 2000, the Company had approximately $4.4 million of cash and cash equivalents and $53.5 million of unused committed lines of credit with banks to meet its short-term cash needs. Refer to the Statements of Cash Flows for details related to the Company's financing activities. See Note 4 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company historically has relied on issuances of first mortgage bonds and preferred stock, in addition to pollution control revenue bonds issued for its benefit by public authorities, to meet its long-term external financing requirements. Recently, the Company's financings have consisted of unsecured debt and trust preferred securities. The Company has no restrictions on the amounts of unsecured indebtedness it may incur. However, in order to issue first mortgage bonds or preferred stock, the Company is required to meet certain coverage requirements specified in its mortgage indenture and corporate charter. The Company's ability to satisfy all coverage requirements is such that it could issue new first mortgage bonds and preferred stock to provide sufficient funds for all anticipated requirements.

Cautionary Statement Regarding Forward-Looking Information

The Company's 2000 Annual Report contains forward looking and historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "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; the extent and timing of the entry of additional competition in the markets of the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the registrants; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$562,162**	$512,760	$509,118
Sales for resale –			
Non-affiliates	**66,890**	62,354	61,893
Affiliates	**66,995**	66,110	42,642
Other revenues	**18,272**	32,875	36,865
Total operating revenues	**714,319**	674,099	650,518
Operating Expenses:			
Operation --			
Fuel	**215,744**	209,031	197,462
Purchased power –			
Non-affiliates	**73,846**	46,332	29,369
Affiliates	**8,644**	10,703	14,445
Other	**117,146**	114,670	119,011
Maintenance	**56,281**	57,830	57,286
Depreciation and amortization	**66,873**	64,589	59,129
Taxes other than income taxes	**55,904**	51,782	51,462
Total operating expenses	**594,438**	554,937	528,164
Operating Income	**119,881**	119,162	122,354
Other Income (Expense):			
Interest income	**1,137**	1,771	931
Other, net	**(4,126)**	(1,357)	(2,339)
Earnings Before Interest and Income Taxes	**116,892**	119,576	120,946
Interest and Other:			
Interest expense, net	**28,085**	26,861	25,556
Distributions on preferred securities of subsidiary	**6,200**	6,200	6,034
Total interest charges and other, net	**34,285**	33,061	31,590
Earnings Before Income Taxes	**82,607**	86,515	89,356
Income taxes (Note 7)	**30,530**	32,631	32,199
Net Income	**52,077**	53,884	57,157
Dividends on Preferred Stock	**234**	217	636
Net Income After Dividends on Preferred Stock	**$ 51,843**	$ 53,667	$ 56,521

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	**$ 52,077**	$ 53,884	$ 57,157
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**69,915**	68,721	69,633
Deferred income taxes and investment tax credits, net	**(12,516)**	(6,609)	(4,684)
Other, net	**10,686**	3,735	3,463
Changes in certain current assets and liabilities --			
Receivables, net	**(20,212)**	(10,484)	11,308
Fossil fuel stock	**13,101**	(5,656)	(4,917)
Materials and supplies	**1,055**	(2,063)	609
Accounts payable	**15,924**	(2,023)	823
Provision for rate refund	**7,203**	-	-
Other	**12,521**	7,030	(18,471)
Net cash provided from operating activities	**149,754**	106,535	114,921
Investing Activities:			
Gross property additions	**(95,807)**	(69,798)	(69,731)
Other	**(4,432)**	(8,856)	5,990
Net cash used for investing activities	**(100,239)**	(78,654)	(63,741)
Financing Activities:			
Increase (decrease) in notes payable, net	**(12,000)**	23,500	(15,500)
Proceeds --			
Other long-term debt	**-**	50,000	50,000
Preferred securities	**-**	-	45,000
Capital contributions from parent company	**12,222**	2,294	522
Retirements --			
First mortgage bonds	**-**	-	(45,000)
Other long-term debt	**(1,853)**	(27,074)	(8,326)
Preferred stock	**-**	-	(9,455)
Payment of preferred stock dividends	**(234)**	(271)	(792)
Payment of common stock dividends	**(59,000)**	(61,300)	(67,200)
Other	**(22)**	(246)	(4,167)
Net cash used for financing activities	**(60,887)**	(13,097)	(54,918)
Net Change in Cash and Cash Equivalents	**(11,372)**	14,784	(3,738)
Cash and Cash Equivalents at Beginning of Period	**15,753**	969	4,707
Cash and Cash Equivalents at End of Period	**$ 4,381**	$ 15,753	$ 969
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$32,277**	$27,670	$28,044
Income taxes (net of refunds)	**42,252**	29,462	38,782

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

Assets	**2000**	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 4,381**	$ 15,753
Receivables --		
Customer accounts receivable	**69,820**	55,108
Other accounts and notes receivable	**2,179**	4,325
Affiliated companies	**15,026**	7,104
Accumulated provision for uncollectible accounts	**(1,302)**	(1,026)
Fossil fuel stock, at average cost	**16,768**	29,869
Materials and supplies, at average cost	**29,033**	30,088
Regulatory clauses under recovery	**2,112**	11,611
Other	**6,543**	5,354
Total current assets	**144,560**	158,186
Property, Plant, and Equipment:		
In service	**1,892,023**	1,853,664
Less accumulated provision for depreciation	**867,260**	821,970
	1,024,763	1,031,694
Construction work in progress	**71,008**	34,164
Total property, plant, and equipment	**1,095,771**	1,065,858
Other Property and Investments	**4,510**	1,481
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 7)	**15,963**	25,264
Prepaid pension costs (Note 2)	**23,491**	17,734
Debt expense, being amortized	**2,392**	2,526
Premium on reacquired debt, being amortized	**15,866**	17,360
Other	**12,943**	20,086
Total deferred charges and other assets	**70,655**	82,970
Total Assets	**$1,315,496**	$1,308,495

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	2000	1999
	(in thousands)	
Current Liabilities:		
Notes payable	**$ 43,000**	$ 55,000
Accounts payable --		
Affiliated	**17,558**	14,878
Other	**38,153**	22,581
Customer deposits	**13,474**	12,778
Taxes accrued --		
Income taxes	**3,864**	4,889
Other	**8,749**	7,707
Interest accrued	**8,324**	9,255
Provision for rate refund	**7,203**	-
Vacation pay accrued	**4,512**	4,199
Regulatory clauses over recovery	**6,848**	3,125
Other	**1,584**	1,836
Total current liabilities	**153,269**	136,248
Long-term debt (See accompanying statements)	**365,993**	367,449
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 7)	**155,074**	162,776
Deferred credits related to income taxes (Note 7)	**38,255**	49,693
Accumulated deferred investment tax credits	**25,792**	27,712
Employee benefits provisions	**34,507**	31,735
Other	**25,992**	21,333
Total deferred credits and other liabilities	**279,620**	293,249
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements)	**85,000**	85,000
Preferred stock (See accompanying statements)	**4,236**	4,236
Common stockholder's equity (See accompanying statements)	**427,378**	422,313
Total Liabilities and Stockholder's Equity	**$1,315,496**	$1,308,495

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Gulf Power Company 2000 Annual Report

		2000	1999	2000	1999
		(in thousands)		*(percent of total)*	
Long Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
July 1, 2003	6.125%	**$ 30,000**	$ 30,000		
November 1, 2006	6.50%	**25,000**	25,000		
January 1, 2026	6.875%	**30,000**	30,000		
Total first mortgage bonds		**85,000**	85,000		
Long-term notes payable --					
7.50% due June 30, 2037		**20,000**	20,000		
6.70% due June 30, 2038		**48,073**	49,926		
7.05% due August 15, 2004		**50,000**	50,000		
Total long-term notes payable		**118,073**	119,926		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.25% to 6.30% due 2006-2026		**108,700**	108,700		
Variable rates (3.70% at 1/1/00) due 2024		**-**	20,000		
Non-collateralized:					
Variable rates (5.10% to 5.30% at 1/1/01) due 2022-2024		**60,930**	40,930		
Total other long-term debt		**169,630**	169,630		
Unamortized debt premium (discount), net		**(6,710)**	(7,107)		
Total long-term debt (annual interest requirement -- $23.2 million)		**365,993**	367,449	**41.5%**	41.8%
Cumulative Preferred Stock:					
$100 par value, 4.64% to 5.44%		**4,236**	4,236		
Total (annual dividend requirement -- $0.2 million)		**4,236**	4,236	**0.5%**	0.5%
Company Obligated Mandatorily Redeemable Preferred Securities:					
$25 liquidation value --					
7.00%		**45,000**	45,000		
7.63%		**40,000**	40,000		
Total (annual distribution requirement -- $6.2 million)		**85,000**	85,000	**9.6%**	9.7%
Common Stockholder's Equity:					
Common stock, without par value --					
Authorized and outstanding - 992,717 shares in 2000 and 1999		**38,060**	38,060		
Paid-in capital		**233,476**	221,254		
Premium on preferred stock		**12**	12		
Retained earnings		**155,830**	162,987		
Total common stockholder's equity		**427,378**	422,313	**48.4%**	48.0%
Total Capitalization		**$882,607**	$878,998	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2000, 1999, and 1998
Gulf Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1998	$38,060	$218,438	$12	$172,208	$428,718
Net income after dividends on preferred stock	-	-	-	56,521	56,521
Capital contributions from parent company	-	522	-	-	522
Cash dividends on common stock	-	-	-	(57,200)	(57,200)
Other	-	-	-	(909)	(909)
Balance at December 31, 1998	38,060	218,960	12	170,620	427,652
Net income after dividends on preferred stock	-	-	-	53,667	53,667
Capital contributions from parent company	-	2,294	-	-	2,294
Cash dividends on common stock	-	-	-	(61,300)	(61,300)
Balance at December 31, 1999	38,060	221,254	12	162,987	422,313
Net income after dividends on preferred stock	-	-	-	**51,843**	**51,843**
Capital contributions from parent company	-	**12,222**	-	-	**12,222**
Cash dividends on common stock	-	-	-	**(59,000)**	**(59,000)**
Balance at December 31, 2000	**$38,060**	**$233,476**	**$12**	**$155,830**	**$427,378**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, Southern Company Services (SCS), Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Mirant Corporation (Mirant) – formerly Southern Energy, Inc., -- Southern Nuclear Operating Company (Southern Nuclear), and other direct and indirect subsidiaries. The integrated Southeast utilities – Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric -- provide electric service in four states. Gulf Power Company provides electric service to the northwest panhandle of Florida. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power --are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). The system service company provides, at cost, specialized services to Southern Company and 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 Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

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 Florida Public Service Commission (FPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the FPSC and the FERC. 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.

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, 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 operations. Costs for these services amounted to $44 million, $43 million, and $40 million during 2000, 1999, and 1998, respectively.

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 to the Company 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:

	2000	1999
	(in thousands)	
Deferred income tax charges	**$15,963**	$25,264
Deferred loss on reacquired debt	**15,866**	17,360
Environmental remediation	**7,638**	5,745
Vacation pay	**4,512**	4,199
Regulatory clauses under (over) recovery, net	**(4,736)**	8,486
Accumulated provision for rate refunds	**(7,203)**	-
Accumulated provision for property damage	**(8,731)**	(5,528)
Deferred income tax credits	**(38,255)**	(49,693)
Other, net	**(1,074)**	(1,255)
Total	**$(16,020)**	$ 4,578

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 any impairment to other assets, including plant, and write down the assets, if impaired, to their fair value.

Revenues and Regulatory Cost Recovery Clauses

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its service area located in northwest Florida 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. The Company's retail electric rates include provisions to annually adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company also has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted monthly for differences between recoverable costs and amounts actually reflected in current rates.

The Company has a diversified base of customers and no single customer or industry comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged significantly less than 1 percent of revenues.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.8 percent in 2000, 1999, and 1998. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost -- together with the cost of removal, less salvage -- is charged to the accumulated provision for depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Also, the provision for depreciation expense includes an amount for the expected cost of removal of facilities.

Income Taxes

The Company uses the liability method of accounting for 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. The Company is included in the consolidated federal income tax return of Southern Company.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost. 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 maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property (exclusive of minor items of property) is charged to utility plant.

Cash and Cash Equivalents

Temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Financial Instruments

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

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
At December 31, 2000	**$365,993**	**$364,697**
At December 31, 1999	$367,449	$349,791
Capital trust preferred securities:		
At December 31, 2000	**$85,000**	**$80,988**
At December 31, 1999	$85,000	$69,092

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

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.

Provision for Injuries and Damages

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by regulatory authorities, the Company provides for the uninsured costs of injuries and damages by charges to income amounting to $1.2 million annually. The expense of settling claims is charged to the provision to the extent available. The accumulated provision of $1.2 million and $1.8 million at December 31, 2000 and 1999, respectively, is included in other current liabilities in the accompanying Balance Sheets.

Provision for Property Damage

The Company provides for the cost of repairing damages from major storms and other uninsured property damages. This includes the full cost of major storms and other damages to its transmission and distribution lines and the cost of uninsured damages to its generation and other property. The expense of such damages is charged to the provision account. At December 31, 2000 and 1999, the accumulated provision for property damage was $8.7 million and $5.5 million, respectively. The FPSC approved annual accrual to the accumulated provision for property damage is $3.5 million, with a target level for the accumulated provision account between $25.1 and $36.0 million. The FPSC has also given the Company the flexibility to increase its annual accrual amount above $3.5 million at the Company's discretion. The Company accrued $3.5 million in 2000, $5.5 million in 1999, and $6.5 million in 1998 to the accumulated provision for property damage. The Company charged $0.3 million, $1.6 million, and $4.2 million against the provision account in 2000, 1999, and 1998 respectively.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, non-contributory pension plan that covers substantially all regular employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits when they retire. Trusts are funded to the extent required by the Company's regulatory commissions. In late 2000, the Company adopted several pension and postretirement benefit plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase the Company's annual pension and postretirement benefits costs by approximately $1.2 million and $0.6 million, respectively. The measurement date for plan assets and obligations is September 30 for each year.

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$141,967**	$143,012
Service cost	**4,282**	4,490
Interest cost	**10,394**	9,440
Benefits paid	**(6,973)**	(6,862)
Actuarial gain and employee transfers, net	**(689)**	(8,113)
Balance at end of year	**$148,981**	$141,967

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$241,485**	$212,934
Actual return on plan assets	**43,833**	35,971
Benefits paid	**(6,973)**	(6,862)
Employee transfers	**4,921**	(558)
Balance at end of year	**$283,266**	$241,485

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

	2000	1999
	(in thousands)	
Funded status	**$134,286**	$99,518
Unrecognized transition obligation	**(3,602)**	(4,323)
Unrecognized prior service cost	**4,121**	4,495
Unrecognized net gain	**(111,314)**	(81,956)
Prepaid asset recognized in the Balance Sheets	**$ 23,491**	$17,734

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

	2000	1999	1998
Service cost	**$4,282**	$4,490	$ 4,107
Interest cost	**10,394**	9,440	9,572
Expected return on plan assets	**(17,504)**	(15,968)	(14,827)
Recognized net gain	**(2,582)**	(1,579)	(1,891)
Net amortization	**(347)**	(347)	(347)
Net pension income	**$(5,757)**	$(3,964)	$(3,386)

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$48,010**	$49,303
Service cost	**896**	1,087
Interest cost	**3,515**	3,261
Benefits paid	**(1,462)**	(1,177)
Actuarial gain and employee transfers, net	**(934)**	(4,464)
Balance at end of year	**$50,025**	$48,010

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$11,196**	$ 9,603
Actual return on plan assets	**2,079**	1,525
Employer contributions	**1,575**	1,245
Benefits paid	**(1,462)**	(1,177)
Balance at end of year	**$13,388**	$11,196

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

	2000	1999
	(in thousands)	
Funded status	**$(36,638)**	$(36,814)
Unrecognized transition obligation	**4,368**	4,723
Unrecognized prior service cost	**2,582**	2,741
Unrecognized net loss	**496**	2,620
Fourth quarter contributions	**316**	300
Accrued liability recognized in the Balance Sheets	**$(28,876)**	$(26,430)

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

	2000	1999	1998
Service cost	**$ 896**	$ 1,087	$ 946
Interest cost	**3,515**	3,261	3,123
Expected return on plan assets	**(901)**	(794)	(717)
Transition obligation	**355**	356	356
Prior service cost	**159**	159	119
Recognized net loss	**13**	264	128
Net postretirement cost	**$ 4,037**	$ 4,333	$3,955

The weighted average rates assumed in the actuarial calculations for both the pension plan and postretirement benefits were:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00%**	5.00%
Long-term return on plan assets	**8.50%**	8.50%

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.3 percent for 2000, decreasing gradually to 5.5 percent through the year 2005, 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, 2000 as follows (in thousands):

	1 Percent Increase	1 Percent Decrease
Benefit obligation	$3,187	$2,874
Service and interest costs	$278	$247

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 2000, 1999, and 1998 were $2.2 million, $2.0 million, and $2.0 million, respectively.

Work Force Reduction Programs

The Company recorded costs related to work force reduction programs of $0.6 million in 2000, $0.2 million in 1999, and $2.8 million in 1998. The Company has also incurred its pro rata share for the costs of affiliated companies' programs. The costs related to these programs were $1.2 million for 2000, $0.6 million for 1999, and $0.2 million for 1998. The Company has expensed all costs related to these work force reduction programs.

3. CONTINGENCIES AND REGULATORY MATTERS

Environmental Cost Recovery

In 1993, the Florida Legislature adopted legislation for an Environmental Cost Recovery Clause (ECRC), which allows a utility to petition the FPSC for recovery of all prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital.

In 1994, the FPSC approved the Company's initial petition under the ECRC for recovery of environmental costs. During 2000, 1999, and 1998, the Company recorded ECRC revenues of $9.9 million, $11.5 million, and $8.0 million, respectively.

At December 31, 2000, the Company's liability for the estimated costs of environmental remediation projects for known sites was $7.6 million. These estimated costs are expected to be expended from 2001 through 2006. These projects have been approved by the FPSC for recovery through the ECRC discussed above. Therefore, the Company recorded $1.2 million in current assets and current liabilities and $6.4 million in deferred assets and deferred liabilities representing the future recoverability of these costs.

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and SCS. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, including the five facilities mentioned previously and the Company's Plants Crist and Scherer. See Note 5 under "Joint Ownership Agreements" related to the Company's ownership interest in Georgia Power's Plant Scherer Unit No. 3. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. The Company believes that its integrated utilities 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 Revenue Sharing Plan

In early 1999, the FPSC staff and the Company became involved in discussions primarily related to reducing the Company's authorized rate of return. On October 1, 1999, the Office of Public Counsel, the Coalition for Equitable Rates, the Florida Industrial Power Users Group, and the Company jointly filed a petition to resolve the issues. The stipulation included a reduction to retail base rates of $10 million annually and provides for revenues to be shared within set ranges for 1999 through 2002. Customers receive two-thirds of any revenue within the sharing range and the Company retains one-third. Any revenue above this range is refunded to the customers. The stipulation also included authorization for the Company, at its discretion, to accrue up to an additional $5 million to the property insurance reserve and $1 million to amortize a regulatory asset related to the corporate office. The Company also filed a request to prospectively reduce its authorized ROE range from 11 to 13 percent to 10.5 to 12.5 percent in order to help ensure that the FPSC would approve the stipulation. The FPSC approved both the stipulation and the ROE request with an effective date of November 4, 1999. The Company is currently planning to seek additional rate relief to recover costs related to the Smith Unit 3 combined cycle facility scheduled to be placed in-service in June of 2002.

For calendar year 2000, the Company's retail revenue range for sharing was $352 million to $368 million to be shared between the Company and its retail customers on the one-third/two-thirds basis. Actual retail revenues in 2000 were $362.4 million and the Company recorded revenues subject to refund of $6.9 million. The estimated refund with interest of $0.3 million was reflected in customer billings in February 2001. In addition to the refund the Company amortized $1 million of the regulatory assets related to the corporate office. For calendar year 2001, the Company's retail revenue range for sharing is $358 million to $374 million. For calendar year 2002, there are specified sharing ranges for each month from the expected in-service date of Smith Unit 3 until the end of the year. The sharing plan will expire at the earlier of the in-service date of Smith Unit 3 or December 31, 2002.

4. FINANCING AND COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $279 million in 2001, $96 million in 2002, and $76 million in 2003. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; revised load growth estimates; changes in environmental regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2000, significant purchase commitments were outstanding in connection with the construction program. The Company has budgeted $199.2 million for the years 2001 and 2002 for the estimated cost of a 574 megawatt combined cycle gas generating unit to be located in the eastern portion of its service area. The unit is expected to have an in-service date of June 2002. The Company's remaining construction program is related to maintaining and upgrading the transmission, distribution, and generating facilities.

Bank Credit Arrangements

At December 31, 2000, the Company had $61.5 million of lines of credit with banks subject to renewal June 1 of each year, of which $53.5 million remained unused. In addition, the Company has two unused committed lines of credit totaling $61.9 million that were established for liquidity support of its variable rate pollution control bonds. In connection with these credit lines, the Company has agreed to pay commitment fees and/or to maintain compensating balances with the banks. The compensating balances, which represent substantially all of the cash of the Company except for daily working funds and like items, are not legally restricted from withdrawal. In addition, the Company has bid-loan facilities with seven major money center banks that total $130 million, of which $35 million was committed at December 31, 2000.

Assets Subject to Lien

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

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into contract commitments for the procurement of fuel. In some cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated obligations at December 31, 2000 were as follows:

Year	Fuel
	(in millions)
2001	$139
2002	91
2003	90
2004	92
2005	93
2006-2024	473
Total commitments	$978

Lease Agreements

In 1989, the Company and Mississippi Power jointly entered into a twenty-two year operating lease agreement for the use of 495 aluminum railcars. In 1994, a second lease agreement for the use of 250 additional aluminum railcars was entered into for twenty-two years. Both of these leases are for the transportation of coal to Plant Daniel. At the end of each lease term, the Company has the option to renew the lease. In 1997, three additional lease agreements for 120 cars each were entered into for three years, with a monthly renewal option for up to an additional nine months.

The Company, as a joint owner of Plant Daniel, is responsible for one half of the lease costs. The lease costs are charged to fuel inventory and are allocated to fuel expense as the fuel is used. The Company's share of the lease costs charged to fuel inventories was $2.1 million in 2000 and $2.8 million in 1999. The annual amounts for 2001 through 2005 are expected to be $1.9 million, $1.9 million, $1.9 million, $2.0 million, and $2.0 million, respectively, and after 2005 are expected to total $13.8 million.

5. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel, a steam-electric generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of the plant.

The Company and Georgia Power jointly own Plant Scherer Unit No. 3. Plant Scherer is a steam-electric generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's pro rata share of expenses related to both plants is included in the corresponding operating expense accounts in the Statements of Income.

At December 31, 2000, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit No. 3 (coal-fired)	Plant Daniel (coal-fired)
	(in thousands)	
Plant In Service	$185,778(1)	$232,074
Accumulated Depreciation	$70,207	$118,504
Construction Work in Progress	$252	$2,006
Nameplate Capacity (2) (megawatts)	205	500
Ownership	25%	50%

(1) Includes net plant acquisition adjustment.
(2) Total megawatt nameplate capacity:
Plant Scherer Unit No. 3: 818
Plant Daniel: 1,000

6. LONG-TERM POWER SALES AGREEMENTS

The Company and the other operating affiliates have long-term contractual agreements for the sale of capacity to certain non-affiliated utilities located outside the system's service area. The unit power sales agreements are firm and pertain to capacity related to specific generating units. Because the energy is generally sold at cost under these agreements, profitability is primarily affected by revenues from capacity sales. The capacity revenues from these sales were $20.3 million in 2000, $19.8 million in 1999, and $22.5 million in 1998. Capacity revenues increased slightly in 2000 due to the recovery of higher operating expenses experienced during the year.

Unit power from specific generating plants of Southern Company is currently being sold to Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), and Jacksonville Electric Authority (JEA). Under these agreements, 209 megawatts of net dependable capacity were sold by the Company during 2000. Sales will increase slightly to 210 megawatts per year in 2001 and remain close to that level, unless reduced by FP&L, FPC, and JEA for the periods after 2001 with a minimum of three years notice, until the expiration of the contracts in 2010.

7. INCOME TAXES

At December 31, 2000, the tax-related regulatory assets to be recovered from customers were $16.0 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 2000, the tax-related regulatory liabilities to be credited to customers were $38.3 million. 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 federal and state income tax provisions are as follows:

	2000	1999	1998
	(in thousands)		
Total provision for income taxes:			
Federal--			
Current	**$37,250**	$33,973	$31,746
Deferred	**(11,159)**	(6,107)	(4,467)
	26,091	27,866	27,279
State--			
Current	**5,796**	5,267	5,137
Deferred	**(1,357)**	(502)	(217)
	4,439	4,765	4,920
Total	**$30,530**	$32,631	$32,199

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:

	2000	1999
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$172,646**	$168,662
Other	**14,262**	24,272
Total	**186,908**	192,934
Deferred tax assets:		
Federal effect of state deferred taxes	**8,703**	9,293
Postretirement benefits	**9,205**	8,456
Other	**14,742**	12,526
Total	**32,650**	30,275
Net deferred tax liabilities	**154,258**	162,659
Less current portion, net	**(816)**	(117)
Accumulated deferred income taxes in the Balance Sheets	**$155,074**	$162,776

Deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation and amortization in the Statements of Income. Credits amortized in this manner amounted to $1.9 million in 2000, 1999, and 1998. At December 31, 2000, 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:

	2000	1999	1998
Federal statutory rate	**35%**	35%	35%
State income tax, net of federal deduction	**4**	4	4
Non-deductible book depreciation	**1**	1	1
Difference in prior years' deferred and current tax rate	**(2)**	(2)	(2)
Other, net	**(1)**	-	(2)
Effective income tax rate	**37%**	38%	36%

The Company and the other subsidiaries of Southern Company file a consolidated federal tax return. Under a joint consolidated income tax agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis.

8. COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES

In January 1997, Gulf Power Capital Trust I (Trust I), of which the Company owns all of the common securities, issued $40 million of 7.625 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust I are $41 million aggregate principal amount of the Company's 7.625 percent junior subordinated notes due December 31, 2036.

In January 1998, Gulf Power Capital Trust II (Trust II), of which the Company owns all of the common securities, issued $45 million of 7.0 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust II are $46 million aggregate principal amount of the Company's 7.0 percent junior subordinated notes due December 31, 2037.

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 payment obligations with respect to the preferred securities of Trust I and Trust II. Trust I and Trust II are subsidiaries of the Company, and accordingly are consolidated in the Company's financial statements.

9. SECURITIES DUE WITHIN ONE YEAR

At December 31, 2000, the Company had an improvement fund requirement of $850,000. The first mortgage bond improvement fund requirement amounts to 1 percent of each outstanding series of bonds authenticated under the indenture prior to January 1 of each year, other than those issued to collateralize pollution control revenue bond obligations. The requirement may be satisfied by depositing cash, reacquiring bonds, or by pledging additional property equal to 1 and 2/3 times the requirement.

10. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture contains various common stock dividend restrictions, which remain in effect as long as the bonds are outstanding. At December 31, 2000, retained earnings of $127 million were restricted against the payment of cash dividends on common stock under the terms of the mortgage indenture.

11. QUARTERLY FINANCIAL DATA (Unaudited)

Summarized quarterly financial data for 2000 and 1999 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in thousands)	
March 2000	**$138,498**	**$16,007**	**$4,653**
June 2000	**182,120**	**30,505**	**12,927**
September 2000	**232,533**	**52,614**	**26,438**
December 2000	**161,168**	**20,755**	**7,825**
March 1999	$134,506	$15,665	$ 4,799
June 1999	166,815	29,253	13,226
September 1999	218,264	54,429	28,582
December 1989	154,514	19,815	7,060

The Company's business is influenced by seasonal weather conditions and the timing of rate changes, among other factors.

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SELECTED FINANCIAL AND OPERATING DATA 1996-2000
Gulf Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)	**$714,319**	$674,099	$650,518	$625,856	$634,365
Net Income after Dividends on Preferred Stock (in thousands)	**$51,843**	$53,667	$56,521	$57,610	$57,845
Cash Dividends on Common Stock (in thousands)	**$59,000**	$61,300	$57,200	$64,600	$58,300
Return on Average Common Equity (percent)	**12.20**	12.63	13.20	13.33	13.27
Total Assets (in thousands)	**$1,315,496**	$1,308,495	$1,267,901	$1,265,612	$1,308,366
Gross Property Additions (in thousands)	**$95,807**	$69,798	$69,731	$54,289	$61,386
Capitalization (in thousands):					
Common stock equity	**$427,378**	$422,313	$427,652	$428,718	$435,758
Preferred stock	**4,236**	4,236	4,236	13,691	65,102
Company obligated mandatorily redeemable preferred securities	**85,000**	85,000	85,000	40,000	-
Long-term debt	**365,993**	367,449	317,341	296,993	331,880
Total (excluding amounts due within one year)	**$882,607**	$878,998	$834,229	$779,402	$832,740
Capitalization Ratios (percent):					
Common stock equity	**48.4**	48.0	51.3	55.0	52.3
Preferred stock	**0.5**	0.5	0.5	1.8	7.8
Company obligated mandatorily redeemable preferred securities	**9.6**	9.7	10.2	5.1	-
Long-term debt	**41.5**	41.8	38.0	38.1	39.9
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+**	AA-	AA-	AA-	A+
Fitch	**AA-***	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	A-	A	A	A
Fitch	**A***	A	A+	A+	A+
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	-
Standard and Poor's	**A**	A	A	A	-
Fitch	**A+***	A+	A+	A+	-
Customers (year-end):					
Residential	**321,731**	315,240	307,077	300,257	291,196
Commercial	**47,666**	47,728	46,370	44,589	43,196
Industrial	**280**	267	257	267	278
Other	**442**	316	268	264	162
Total	**370,119**	363,551	353,972	345,377	334,832
Employees (year-end):	**1,327**	1,339	1,328	1,328	1,384

*Effective 1/22/01 the Fitch Security Ratings for First Mortgage Bonds, Preferred Stock, and Unsecured Long-Term Debt are A+, A-, and A respectively.

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Gulf Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands):					
Residential	**$ 308,728**	$277,311	$ 276,208	$ 277,609	$ 285,498
Commercial	**181,584**	165,871	160,960	164,435	164,181
Industrial	**76,539**	67,404	69,850	77,492	78,994
Other	**(4,689)**	2,174	2,100	2,083	2,056
Total retail	**562,162**	512,760	509,118	521,619	530,729
Sales for resale - non-affiliates	**66,890**	62,354	61,893	63,697	63,201
Sales for resale - affiliates	**66,995**	66,110	42,642	16,760	17,762
Total revenues from sales of electricity	**696,047**	641,224	613,653	602,076	611,692
Other revenues	**18,272**	32,875	36,865	23,780	22,673
Total	**$714,319**	$674,099	$650,518	$625,856	$634,365
Kilowatt-Hour Sales (in thousands):					
Residential	**4,790,038**	4,471,118	4,437,558	4,119,492	4,159,924
Commercial	**3,379,449**	3,222,532	3,111,933	2,897,887	2,808,634
Industrial	**1,924,749**	1,846,237	1,833,575	1,903,050	1,808,086
Other	**18,730**	19,296	18,952	18,101	17,815
Total retail	**10,112,966**	9,559,183	9,402,018	8,938,530	8,794,459
Sales for resale - non-affiliates	**1,705,486**	1,561,972	1,341,990	1,531,179	1,534,097
Sales for resale - affiliates	**1,916,526**	2,511,983	1,758,150	848,135	709,647
Total	**13,734,978**	13,633,138	12,502,158	11,317,844	11,038,203
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**6.45**	6.20	6.22	6.74	6.86
Commercial	**5.37**	5.15	5.17	5.67	5.85
Industrial	**3.98**	3.65	3.81	4.07	4.37
Total retail	**5.56**	5.36	5.41	5.84	6.03
Sales for resale	**3.70**	3.15	3.37	3.38	3.61
Total sales	**5.07**	4.70	4.91	5.32	5.54
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,992**	14,318	14,577	13,894	14,457
Residential Average Annual Revenue Per Customer	**$966.26**	$888.01	$907.35	$936.30	$992.17
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,188**	2,188	2,188	2,174	2,174
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,154**	2,085	2,040	1,844	2,136
Summer	**2,285**	2,161	2,146	2,032	1,961
Annual Load Factor (percent)	**55.4**	55.2	55.3	55.5	51.4
Plant Availability Fossil-Steam (percent):	**85.2**	87.2	87.6	91.0	91.8
Source of Energy Supply (percent):					
Coal	**87.8**	89.8	89.2	87.1	87.8
Oil and gas	**1.6**	2.5	2.0	0.4	0.5
Purchased power -					
From non-affiliates	**7.6**	5.9	5.5	3.5	2.7
From affiliates	**3.0**	1.8	3.3	9.0	9.0
Total	**100.0**	100.0	100.0	100.0	100.0

MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT

The management of Mississippi 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 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 upon 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 audit committee of the board of directors, composed of four independent directors, provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors, and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls, and financial reporting matters. The internal auditors and independent public accountants have access to the members of the audit committee 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 Mississippi Power Company in conformity with accounting principles generally accepted in the United States.

Dwight H. Evans
President and Chief Executive Officer

Michael W. Southern
Vice President, Secretary, Treasurer and
Chief Financial Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Mississippi Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (a Mississippi corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2000 and 1999, 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, 2000. 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 II-151 through II-166) referred to above present fairly, in all material respects, the financial position of Mississippi Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Mississippi Power Company's 2000 net income after dividends on preferred stock of $55 million increased $0.2 million over 1999 earnings of $54.8 million, which were $0.3 million less than 1998 earnings of $55.1 million.

Revenues

Operating revenues for the Company in 2000 and the changes from the prior year are as follows:

	Amount	Increase (Decrease) From Prior Year	
	2000	2000	1999
		(in millions)	
Retail --			
Base Revenues	**$287,253**	$ (5,854)	$17,462
Fuel cost recovery and other	**211,298**	34,971	9,405
Total retail	**498,551**	29,117	26,867
Sales for resale --			
Non-affiliates	**145,931**	14,927	9,779
Affiliates	**27,915**	8,469	1,161
Total sales for resale	**173,846**	23,396	10,940
Other operating revenues	**15,205**	2,085	66
Operating revenues	**$687,602**	$54,598	$ 37,873
Percent change		8.6%	6.4%

Total retail revenues for 2000 increased approximately 6.2 percent when compared to 1999. The increase resulted primarily from continued growth in the service area, a positive impact of weather and additional fuel revenues. Retail revenues for 1999 reflected a 6.1 percent increase over the prior year due to the continued growth in the service area, increased fuel revenues, and a true-up of the unbilled revenue estimate.

Fuel revenues generally represent the direct recovery of fuel expense including purchased power. Therefore, changes in recoverable fuel expenses are offset with corresponding changes in fuel revenues and have no effect on net income.

Energy sales to non-affiliates include economy sales and amounts sold under short-term contracts. Sales for resale to non-affiliates are influenced by those utilities' own customer demand, plant availability, and the cost of their predominant fuels.

Included in sales for resale to non-affiliates are revenues from rural electric cooperative associations and municipalities located in southeastern Mississippi. Energy sales to these customers increased 10.9 percent in 2000 and 10.2 percent in 1999, with the related revenues rising 10.8 percent and 12.1 percent, respectively. The customer demand experienced by these utilities is determined by factors very similar to those of the Company. Revenues from other sales outside the service area increased in 2000 and 1999 primarily due to power marketing activities. These increases were offset by increases in purchased power from non-affiliates and, as a result, had no significant effect on net income.

Sales to affiliated companies within the Southern Company electric system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These sales have no material impact on earnings.

Below is a breakdown of kilowatt-hour sales for 2000 and the percent change for the last two years:

	2000	Percent Change	
	KWH	2000	1999
	(in millions)		
Residential	**2,286**	**1.7%**	-
Commercial	**2,883**	**1.3**	8.5%
Industrial	**4,376**	**(0.7)**	18.2
Other	**41**	**2.5**	0.8
Total retail	**9,586**	**0.5**	10.4
Sales for Resale --			
Non-affiliates	**3,675**	**12.9**	3.1
Affiliates	**453**	**(16.2)**	(2.2)
Total	**13,714**	**2.8**	8.0

Total retail kilowatt-hour sales increased slightly in 2000 when compared to 1999 sales, which included an unbilled revenue true-up of approximately 3.5 percent. The increase primarily resulted from the continued growth in the service area and the positive impact of weather. Excluding the impact of the unbilled revenue true-up, all retail customer classes experienced growth in 2000 due to the positive impact of weather, increased tourism, and continued growth in the service area. In 1999, increased tourism and strong growth impacted commercial sales, while industrial sales were impacted by increased production by several larger industrial customers, including one which was shut down in 1998 by Hurricane Georges.

Expenses

Total operating expenses were $565 million in 2000 reflecting an increase of $52 million or 10.1 percent over the prior year. The increase was due primarily to higher fuel and purchased power expenses. In 1999, total operating expenses increased by 6.9 percent over the prior year due primarily to higher fuel expenses.

Fuel costs are the single largest expense for the Company. Fuel expenses for 2000 and 1999 increased 10.7 percent and 10.3 percent, respectively. The increase for each year was due to increased generation and a higher average cost of fuel. The increased generation was due to higher demand for energy across the Southern Company electric system.

In 2000, expenses related to purchased power from non-affiliates increased 40.0 percent, while expenses related to purchased power from affiliates increased 64.7 percent which, in total, resulted in a 51 percent increase when compared to 1999. This increase consisted mostly of energy purchased for power marketing activities which was resold to non-affiliated third parties and had no significant effect on net income. Sales and purchases among the Company and its affiliates will vary from period to period depending on demand and the availability and variable production cost of each generating unit in the Southern Company electric system.

The amount and sources of generation and the average cost of fuel per net kilowatt-hour generated were as follows:

	2000	1999	1998
Total generation (millions of kilowatt hours)	**11,688**	11,599	10,610
Sources of generation (percent) --			
Coal	**83**	81	80
Gas	**17**	19	20
Average cost of fuel per net kilowatt-hour generated (cents) --	**1.80**	1.65	1.62

Other operation expenses decreased 8.2 percent in 2000 primarily due to a decrease in administrative and general expenses. In 1999, other operation expense increased 13.9 percent primarily due to the amortization of costs associated with the workforce reduction plan and higher distribution expenses. Maintenance expense in 2000 increased due to additional scheduled maintenance, while maintenance expense in 1999 decreased due to reduced scheduled maintenance. In 2000, depreciation expenses increased slightly due to growth in plant investment and a new composite depreciation rate, which became effective January 2000. Comparisons of taxes other than income taxes for 2000 and 1999 show increases of 1.7 percent and 4.2 percent, respectively, due to higher municipal franchise taxes resulting from higher retail revenues. Interest on long-term debt increased in 2000 due to higher interest rates and increased debt outstanding.

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of 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 costs does not recognize this economic loss or 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.

Future Earnings Potential

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors ranging from weather to energy sales growth to a less regulated and more competitive environment. Expenses are subject to constant review and cost control programs. The Company is also maximizing the utility of invested capital and minimizing the need for additional capital by refinancing, managing the size of its fuel stockpile, raising generating plant availability and efficiency, and aggressively controlling its construction budget.

The Company currently operates as a vertically integrated utility providing electricity to customers within its traditional service area located in southeastern Mississippi. Prices for electricity provided by the Company to retail customers are set by the Mississippi Public Service Commission (MPSC) under cost-based regulatory principles. The Federal Energy Regulatory Commission (FERC) regulates the Company's wholesale rate schedules, power sales contracts and transmission facilities.

Operating revenues will be affected by any changes in rates under the Performance Evaluation Plan (PEP) -- the Company's performance based ratemaking plan -- and the Environmental Compliance Overview Plan (ECO Plan). PEP has proven to be a stabilizing force on electric rates, with only moderate changes in rates taking place. The ECO Plan provides for recovery of costs (including costs of capital) associated with environmental projects approved by the MPSC, most of which are required to comply with Clean Air Act Amendments of 1990 (Clean Air Act) regulations. The ECO Plan is operated independently of PEP. Compliance costs related to the Clean Air Act could affect earnings if such costs cannot be recovered. The Company's 2000 ECO Plan filed in January 2000 was approved as filed, and resulted in a slight decrease in customer prices. The Company filed its 2001 ECO Plan in January 2001 and, if approved as filed, it will result in a slight increase in customer prices. Refer to Note 3 to the financial statements under "Litigation and Regulatory Matters" for additional information. The Clean Air Act and other important environmental items are discussed later under "Environmental Matters."

Future earnings in the near term will depend upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, changes in 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. The Company anticipates somewhat slower growth in energy sales as the tourism industry stabilizes within its service area. In addition to tourism, the healthcare and retail trade sectors will provide most of the anticipated energy growth for the commercial class of customers, while shipbuilding, chemicals and the U.S. government will provide much of the basis for anticipated growth in the industrial sector.

The electric utility industry in the United States is currently undergoing a period of dramatic change 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 cogeneration plants for a utility's large industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are affected by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers.

Although the Energy Act does not permit retail transmission access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in various stages to promote wholesale and retail competition. Among other things, these initiatives allow customers to choose their electricity provider. As these initiatives materialize, the structure of the utility industry could radically change. In May 2000, the MPSC ordered that its docket reviewing restructuring of the electric industry in the State of Mississippi be suspended. The MPSC found that retail competition may not be in the public interest at this time, and ordered that no further formal hearings would be held on this subject. It found that the current regulatory structure produced reliable low cost power and "should not be changed without clear and convincing demonstration that change would be in the public interest." The MPSC will continue to monitor retail and wholesale restructuring activities throughout the United States and reserves its right to order further formal hearings on the matter should new evidence demonstrate that retail competition would be in the public interest and all customers could receive a reduction in the total cost of their electric service. If the MPSC decides to hold future restructuring hearings on this matter, enactment would require numerous issues to be resolved, including significant ones relating to transmission, prices, and recovery of any stranded costs. The inability of the Company to recover its investment, including regulatory assets, could have a material adverse effect on the financial condition of the Company.

The Company is attempting to minimize or reduce its cost exposure. 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. 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.

Continuing to be a low-cost producer could provide significant opportunities to increase market share and profitability in markets that evolve with changing regulation. Conversely, unless the Company remains a low-cost producer and provides quality service, the Company's energy sales growth could be limited, and this could significantly erode earnings.

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its final ruling on Regional Transmission Organizations (RTOs). The order encourages utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing with the FERC. On October 16, 2000, Southern Company and its integrated utilities including the Company filed a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of the Company and any other participating utilities. Participants would have the option to either maintain their ownership or divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on the Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUHCA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUHCA. These entities are able to own and operate power generating facilities and sell power to affiliates – under certain restrictions.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced the formation of a new subsidiary – Southern Power Company. The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. Southern Power will be the primary growth engine for Southern Company's market-based energy business. Energy from its assets will be marketed to wholesale customers under the Southern Company name.

In accordance with FASB Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pension income of approximately $4.2 million in 2000. Pension income in 2001 is expected to be less as a result of plan amendments. Future pension income is dependent on several factors including trust earnings and changes to the plan. For more information, see Note 2.

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."

Exposure to Market Risks

Due to cost-based rate regulations, 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. Realized gains and losses are recognized in the income statements as incurred. At December 31, 2000, exposure from these activities was not material to the Company's financial statements. Also, based on the Company's overall interest rate exposure at December 31, 2000, a near-term 100 basis point change in interest rates would not materially affect the financial statements.

New Accounting Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

Substantially all of the Company's bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted Statement No. 133 effective January 1, 2001. The impact on net income was immaterial. The application of the new rules is still evolving and further guidance from FASB is expected, which could additionally impact the Company's financial statements. Also, as wholesale energy markets mature, future transactions could result in more volatility in net income and comprehensive income.

FINANCIAL CONDITION

Overview

The principal change in the Company's financial condition during 2000 was the addition of approximately $81 million to utility plant. Funding for these additions and other capital requirements were derived primarily from operations. The Statements of Cash Flows provide additional details.

Financing Activity

In March 2000, the Company issued $100 million of floating rate senior notes due March 28, 2002. The proceeds were used to prepay bank loans of $45 million maturing in November 2001 and $5 million maturing in October 2002. The balance of the $100 million was used to repay a portion of the Company's outstanding short-term debt. The Company plans to continue, to the extent possible, a program to retire higher-cost debt and replace these securities with lower-cost capital. See the Statements of Cash Flows for further details.

Composite financing rates increased for the year 2000 when compared to 1998 and 1999. As of year-end , the composite rates were as follows:

	2000	1999	1998
Composite interest rate on long-term debt	**6.41%**	6.19%	6.14%
Composite preferred stock dividend rate	**6.33%**	6.33%	6.33%
Composite interest rate on preferred securities	**7.75%**	7.75%	7.75%

In 1999, the Company signed an Agreement for Lease and a Lease Agreement with Escatawpa Funding, Limited Partnership ("Escatawpa"), that calls for the Company to design and construct, as agent for Escatawpa, a 1,064 megawatt natural gas combined cycle facility. It is anticipated that the total project will cost approximately $400 million, and upon project completion in mid 2001, the Company intends to lease the facility for an initial term of approximately 10 years. It is anticipated that the annual lease payments will approximate $32 million during the initial term.

Capital Structure

At year-end 2000, the Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, decreased from 50.2 percent in 1999, to 48.1 percent.

Capital Requirements for Construction

The Company's projected construction expenditures for the next three years total $191 million ($62 million in 2001, $60 million in 2002, and $69 million in 2003). The major emphasis within the construction program will be on the upgrade of existing facilities.

Revisions to projected construction expenditures may be necessary because of factors such as changes in business conditions, revised load projections, the availability and cost of capital, changes in environmental regulations, and alternatives such as leasing.

Other Capital Requirements

In addition to the funds required for the Company's construction program, approximately $135 million will be required by the end of 2003 for present sinking fund requirements and 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.

Environmental Matters

On November 3, 1999, the Environmental Protection Agency (EPA), brought a civil action in the U.S. District Court against Alabama Power Company, Georgia Power Company and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously, and the Company's plants Watson and Greene County. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Savannah Electric, and the Company as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include SCS in the new complaint. 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 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 unless such costs can be recovered through regulated rates.

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) were signed into law. Title IV of the Clean Air Act -- the acid rain compliance provision of the law -- significantly affected Southern Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995. As a result of a systemwide compliance strategy, some 50 generating units of Southern Company were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. Construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions compliance totaled approximately $300 million for Southern Company, including approximately $65 million for the Company.

Phase II sulfur dioxide compliance was required in 2000. Southern Company used emission allowances and fuel switching to comply with Phase II requirements. Also, equipment to control nitrogen oxide emissions was installed on additional system fossil-fired units as necessary to meet Phase II limits and ozone non-attainment requirements for metropolitan Atlanta through 2000. Compliance for Phase II and initial ozone non-attainment requirements increased the Company's total construction expenditures through 2000 by approximately $100 million. Phase II compliance did not have a material impact on the Company.

The Company's ECO Plan is designed to allow recovery of costs of compliance with the Clean Air Act, as well as other environmental statutes and regulations. The MPSC reviews environmental projects and the Company's environmental policy through the ECO Plan. Under the ECO Plan, any increase in the annual revenue requirement is limited to 2 percent of retail revenues. The Company's management believes that the ECO Plan provides for recovery of the Clean Air Act costs. See Note 3 to the financial statements under "Environmental Compliance Overview Plan" for additional information.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In July 1997, the EPA revised the national ambient air quality standards for ozone and fine particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. A decision is expected in the spring of 2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rules affect 21 states that at present do not include Mississippi. The EPA is presently evaluating whether or not to bring an additional 15 states including Mississippi, under this regional nitrogen oxide rule.

In December 2000, the EPA completed its utility study for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls would likely be required around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are reviewing and evaluating various matters including: emission control strategies for ozone non-attainment areas; additional controls for hazardous air pollutant emissions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. Under these various laws and regulations, the Company could incur costs to clean up properties currently or previously owned. Upon identifying potential sites, the Company conducts studies, when possible, to determine the extent of any required cleanup costs. Should remediation be determined to be probable, reasonable estimates of costs to clean up such sites are developed and recognized in the financial statements.

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect the Company. The impact of new legislation -- if any -- will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for lawsuits alleging damages caused by electromagnetic fields or other environmental concerns. The likelihood or outcome of such potential lawsuits cannot be determined at this time.

Sources of Capital

To meet short-term cash needs and contingencies, the Company had at December 31, 2000 approximately $7.5 million of cash and cash equivalents and approximately $117 million of unused committed credit agreements. The Company had $56 million of short-term notes payable outstanding at year-end 2000.

It is anticipated that the funds required for construction and other purposes, including compliance with environmental regulations, will be derived from sources similar to those used in the past. These sources were primarily the issuance of first mortgage bonds and preferred securities, in addition to pollution control revenue bonds issued for the Company's benefit by public authorities. The Company also issued unsecured debt in 1998.

The Company has no restrictions on the amounts of unsecured indebtedness it may incur. However, the Company is required to meet certain coverage requirements specified in its mortgage indenture and corporate charter to issue new first mortgage bonds and preferred stock. The Company's coverage ratios are high enough to permit, at present interest rate levels, any foreseeable security sales. The amount of securities which the Company will be permitted to issue in the future will depend upon market conditions and other factors prevailing at that time.

Cautionary Statement Regarding Forward-Looking Information

This Annual Report includes forward-looking statements in addition to historical information. Forward-looking information includes, among other things, statements concerning projected sales growth and scheduled completion of new generation. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "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 extent and timing of the entry of additional competition in the markets of the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options, that may be pursued by the Company; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

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STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998
Mississippi Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$498,551**	$469,434	$442,567
Sales for resale --			
Non-affiliates	**145,931**	131,004	121,225
Affiliates	**27,915**	19,446	18,285
Other revenues	**15,205**	13,120	13,054
Total operating revenues	**687,602**	633,004	595,131
Operating Expenses:			
Operation --			
Fuel	**191,127**	172,686	156,539
Purchased power --			
Non-affiliates	**56,082**	40,080	33,872
Affiliates	**51,057**	31,007	36,037
Other	**115,055**	125,291	109,993
Maintenance	**52,750**	47,085	50,404
Depreciation and amortization	**50,275**	49,206	47,450
Taxes other than income taxes	**48,686**	47,893	45,965
Total operating expenses	**565,032**	513,248	480,260
Operating Income	**122,570**	119,756	114,871
Other Income (Expense):			
Interest income	**347**	189	863
Other, net	**(647)**	1,675	2,498
Earnings Before Interest and Income Taxes	**122,270**	121,620	118,232
Interest Expense and Other:			
Interest expense, net	**28,101**	27,969	23,746
Distributions on preferred securities of subsidiary	**2,712**	2,712	2,712
Total interest charges and other, net	**30,813**	30,681	26,458
Earnings Before Income Taxes	**91,457**	90,939	91,774
Income taxes	**34,356**	34,117	34,664
Net Income	**57,101**	56,822	57,110
Dividends on Preferred Stock	**2,129**	2,013	2,005
Net Income After Dividends on Preferred Stock	**$ 54,972**	$ 54,809	$ 55,105

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Mississippi Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	**$ 57,101**	$ 56,822	$ 57,110
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**54,638**	53,427	51,517
Deferred income taxes and investment tax credits, net	**752**	(4,143)	11,620
Other, net	**(1,747)**	5,531	(12,175)
Changes in certain current assets and liabilities --			
Receivables, net	**(3,231)**	(39,304)	(5,486)
Fossil fuel stock	**14,577**	(9,379)	(5,767)
Materials and supplies	**(1,056)**	(1,903)	717
Accounts payable	**1,309**	1,391	(389)
Other	**2,952**	14,206	(4,061)
Net cash provided from operating activities	**125,295**	76,648	93,086
Investing Activities:			
Gross property additions	**(81,211)**	(75,888)	(68,231)
Other	**(9,153)**	1,009	(324)
Net cash used for investing activities	**(90,364)**	(74,879)	(68,555)
Financing Activities:			
Increase (decrease) in notes payable, net	**(1,500)**	44,500	13,000
Proceeds --			
Other long-term debt	**100,000**	59,400	103,520
Capital contributions from parent company	**12,659**	2,028	85
Retirements --			
First mortgage bonds	**-**	-	(75,000)
Other long-term debt	**(81,405)**	(50,456)	(13,020)
Preferred stock	**-**	-	(87)
Payment of preferred stock dividends	**(2,129)**	(2,013)	(2,005)
Payment of common stock dividends	**(54,700)**	(56,100)	(51,700)
Other	**(498)**	(282)	(2,429)
Net cash used for financing activities	**(27,573)**	(2,923)	(27,636)
Net Change in Cash and Cash Equivalents	**7,358**	(1,154)	(3,105)
Cash and Cash Equivalents at Beginning of Period	**173**	1,327	4,432
Cash and Cash Equivalents at End of Period	**$ 7,531**	$ 173	$ 1,327
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$30,570**	$25,486	$26,133
Income taxes (net of refunds)	**28,418**	39,729	26,847

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Mississippi Power Company 2000 Annual Report

Assets	**2000**	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 7,531**	$ 173
Receivables --		
Customer accounts receivable	**72,064**	61,274
Other accounts and notes receivable	**21,843**	23,490
Affiliated companies	**10,071**	16,097
Accumulated provision for uncollectible accounts	**(571)**	(697)
Fossil fuel stock, at average cost	**11,220**	25,797
Materials and supplies, at average cost	**21,694**	20,638
Other	**8,320**	10,013
Total current assets	**152,172**	156,785
Property, Plant, and Equipment:		
In service	**1,665,879**	1,601,399
Less accumulated provision for depreciation	**652,891**	626,841
	1,012,988	974,558
Construction work in progress	**60,951**	68,721
Total property, plant, and equipment	**1,073,939**	1,043,279
Other Property and Investments	**2,268**	1,389
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**13,860**	21,557
Prepaid pension costs	**6,724**	2,488
Debt expense, being amortized	**4,628**	4,355
Premium on reacquired debt, being amortized	**7,168**	8,154
Other	**14,312**	13,129
Total deferred charges and other assets	**46,692**	49,683
Total Assets	**$1,275,071**	$1,251,136

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Mississippi Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	2000	1999
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 20	$ 30,020
Notes payable	56,000	57,500
Accounts payable --		
Affiliated	10,715	17,002
Other	48,146	43,105
Customer deposits	5,274	3,749
Taxes accrued --		
Income taxes	8,769	6,865
Other	36,799	35,534
Interest accrued	4,482	6,733
Vacation pay accrued	5,701	5,218
Other	7,003	7,497
Total current liabilities	182,909	213,223
Long-term debt (See accompanying statements)	370,511	321,802
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	139,909	139,564
Deferred credits related to income taxes	25,603	34,765
Accumulated deferred investment tax credits	23,481	24,695
Employee benefits provisions	34,671	34,268
Workforce reduction plan	9,734	11,272
Other	16,546	12,770
Total deferred credits and other liabilities	249,944	257,334
Company obligated mandatorily redeemable preferred securities of subsidiary trust holding company junior subordinated notes (See accompanying statements)	35,000	35,000
Preferred stock (See accompanying statements)	31,809	31,809
Common stockholder's equity (See accompanying statements)	404,898	391,968
Total Liabilities and Stockholder's Equity	$1,275,071	$1,251,136

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Mississippi Power Company 2000 Annual Report

		2000	1999	2000	1999
			(in thousands)	*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
June 1, 2023	7.45%	**$ 35,000**	$ 35,000		
March 1, 2004	6.60%	**35,000**	35,000		
December 1, 2025	6.875%	**30,000**	30,000		
Total first mortgage bonds		**100,000**	100,000		
Long-term notes payable --					
6.05% due May 1, 2003		**35,000**	35,000		
6.75% due June 30, 2038		**53,179**	54,564		
Adjustable rates (6.61% to 6.78% at 1/1/01) due 2000-2002		**100,000**	80,000		
Total long-term notes payable		**188,179**	169,564		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.65% to 5.80% due 2007-2023		**-**	26,785		
Variable rates (3.90% at 1/1/01) due 2020-2025		**-**	10,600		
Non-collateralized:					
5.65% to 5.80% due 2007-2023		**26,765**			
Variable rates (3.90% to 5.20% at 1/1/01) due 2020-2028		**56,820**	46,220		
Total other long-term debt		**83,585**	83,605		
Unamortized debt premium (discount), net		**(1,233)**	(1,347)		
Total long-term debt (annual interest requirement -- $23.8 million)		**370,531**	351,822		
Less amount due within one year		**20**	30,020		
Long-term debt excluding amount due within one year		**$370,511**	$321,802	**43.9%**	41.2%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2000 and 1999
Mississippi Power Company 2000 Annual Report

	2000	1999	2000	1999
		(in thousands)	*(percent of total)*	
Company Obligated Mandatorily Redeemable Preferred Securities:(Note 8)				
$25 liquidation value --				
7.75%	**$ 35,000**	$ 35,000		
Total (annual distribution requirement -- $2.7 million)	**35,000**	35,000	**4.2**	4.5
Cumulative Preferred Stock:				
$100 par value				
4.40% to 7.00%	**31,809**	31,809		
Total (annual dividend requirement -- $2.0 million)	**31,809**	31,809	**3.8**	4.1
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 1,130,000 shares				
Outstanding - 1,121,000 shares in 2000 and 1999	**37,691**	37,691		
Paid-in capital	**194,161**	181,502		
Premium on preferred stock	**326**	326		
Retained earnings	**172,720**	172,449		
Total common stockholder's equity	**404,898**	391,968	**48.1**	50.2
Total Capitalization	**$842,218**	$780,579	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2000, 1999, and 1998
Mississippi Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1998	$37,691	$179,389	$327	$170,417	$387,824
Net income after dividends on preferred stock	-	-	-	55,105	55,105
Capital contributions from parent company	-	85	-	-	85
Cash dividends on common stock	-	-	-	(51,700)	(51,700)
Other	-	-	(1)	(82)	(83)
Balance at December 31, 1998	37,691	179,474	326	173,740	391,231
Net income after dividends on preferred stock	-	-	-	54,809	54,809
Capital contributions from parent company	-	2,028	-	-	2,028
Cash dividends on common stock	-	-	-	(56,100)	(56,100)
Balance at December 31, 1999	37,691	181,502	326	172,449	391,968
Net income after dividends on preferred stock	-	-	-	**54,972**	**54,972**
Capital contributions from parent company	-	**12,659**	-	-	**12,659**
Cash dividends on common stock	-	-	-	**(54,700)**	**(54,700)**
Other	-	-	-	**(1)**	**(1)**
Balance at December 31, 2000	**$37,691**	**$194,161**	**$326**	**$172,720**	**$404,898**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, a system service company (SCS), Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Southern Nuclear Operating Company (Southern Nuclear), Mirant Corporation -- formerly Southern Energy, Inc. -- and other direct and indirect subsidiaries. The integrated Southeast utilities -- Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company -- provide electric service in four states. Contracts among the integrated Southeast utilities -- related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power -- are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission (SEC). SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the integrated Southeast utilities and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns, and operates power production and delivery facilities and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

Southern Company is registered as a holding company under the Public Utility Holding Company Act of 1935 (PUHCA). Both the 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 Mississippi Public Service Commission (MPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the respective 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.

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

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, 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 operations. Costs for these services amounted to $46.2 million, $45.5 million, and $43.9 million during 2000, 1999, and 1998, respectively.

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 to the Company 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:

	2000	1999
	(in thousands)	
Deferred income tax charges	**$ 13,860**	$ 21,557
Vacation pay	**5,701**	5,218
Premium on reacquired debt	**7,168**	8,154
Property damage reserve	**(3,519)**	(3,082)
Deferred income tax credits	**(25,603)**	(34,765)
Other, net	**(505)**	(349)
Total	**$ (2,898)**	$ (3,267)

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 value.

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 Mississippi, 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. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between actual allowable amounts and the amounts included in rates.

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 continued to average less than 1 percent of revenues.

Depreciation

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.5 percent in 2000 and 3.3 percent in 1999 and 1998. 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 removal of facilities.

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.

Property, Plant and Equipment

Property, plant, and equipment is stated at original cost. 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, if applicable. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense except for the maintenance of coal cars and a portion of the railway track maintenance, which are charged to fuel stock. The cost of replacements of property -- exclusive of minor items of property -- is capitalized.

Cash and Cash Equivalents

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

Financial Instruments

The Company's 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, 2000	**$371**	**$362**
At December 31, 1999	$353	$334
Capital trust preferred securities:		
At December 31, 2000	**$35**	**$34**
At December 31, 1999	$35	$30

The fair values for long-term debt and preferred securities were based on either closing market price or closing price of comparable instruments.

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 used or installed.

Provision for Property Damage

The Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by regulatory authorities, the Company accrues for the cost of such damage by charging expense and crediting an accumulated provision. The cost of repairing damage resulting from such events that individually exceed $50 thousand is charged to the accumulated provision. In 1999, an order from the MPSC increased the maximum Property Damage Reserve from $18 million to $23 million and allows an annual accrual of up to $4.6 million. In 2000, the Company provided for such costs by charges to income of $3.5 million. In 1999 and 1998, the Company provided for such costs by charges to income of $4.4 million and $1.5 million, respectively. As of December 31, 2000, the accumulated provision amounted to $3.5 million.

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed, pension plans that cover substantially all employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all these employees may become eligible for such benefits when they retire. The Company funds trusts to the extent deductible under federal income tax regulations or the extent required by regulatory authorities. In late 2000, the Company adopted several pension and postretirement benefits plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits costs by approximately $1.3 and $0.4 million, respectively. The measurement date for plan assets and obligations is September 30 for each year.

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$139,930**	$142,807
Service cost	**4,272**	4,415
Interest cost	**10,196**	9,377
Benefits paid	**(7,593)**	(8,050)
Actuarial gain and employee transfers	**(1,419)**	(8,619)
Balance at end of year	**$145,386**	$139,930

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$221,487**	$198,100
Actual return on plan assets	**39,737**	33,216
Benefits paid	**(7,593)**	(8,050)
Employee transfers	**3,017**	(1,779)
Balance at end of year	**$256,648**	$221,487

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

	2000	1999
	(in thousands)	
Funded status	**$111,263**	$ 81,557
Unrecognized transition obligation	**(3,269)**	(3,814)
Unrecognized prior service cost	**4,577**	4,991
Unrecognized net gain	**(105,847)**	(80,246)
Prepaid asset recognized in the Balance Sheets	**$ 6,724**	$ 2,488

Components of the plans' net periodic cost were as follows:

	2000	1999	1998
	(in thousands)		
Service cost	**$ 4,272**	$ 4,415	$ 3,848
Interest cost	**10,196**	9,377	9,613
Expected return on plan assets	**(15,910)**	(14,681)	(13,817)
Recognized net gain	**(2,663)**	(1,721)	(1,956)
Net amortization	**(131)**	(131)	(131)
Net pension income	**$ (4,236)**	$ (2,741)	$(2,443)

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$45,390**	$47,260
Service cost	**830**	982
Interest cost	**3,309**	3,105
Benefits paid	**(2,628)**	(2,256)
Actuarial gain and employee transfers	**(1,949)**	(3,701)
Balance at end of year	**$44,952**	$45,390

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$14,998**	$12,779
Actual return on plan assets	**2,511**	1,818
Employer contributions	**2,961**	2,657
Benefits paid	**(2,627)**	(2,256)
Balance at end of year	**$17,843**	$14,998

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

	2000	1999
	(in thousands)	
Funded status	**$(27,109)**	$(30,392)
Unrecognized transition obligation	**4,275**	4,621
Unrecognized net gain	**(6,632)**	(3,406)
Fourth quarter contributions	**1,065**	931
Accrued liability recognized in the Balance Sheets	**$(28,401)**	$(28,246)

Components of the plans' net periodic cost were as follows:

	2000	1999	1998
	(in thousands)		
Service cost	**$ 830**	$ 981	$ 806
Interest cost	**3,309**	3,105	3,162
Expected return on plan assets	**(1,235)**	(1,100)	(989)
Net amortization	**346**	346	346
Net postretirement cost	**$3,250**	$ 3,332	$ 3,325

The weighted average rates assumed in the actuarial calculations for both the pension plans and postretirement benefits were:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00**	5.00
Long-term return on plan assets	**8.50**	8.50

An additional assumption used in measuring the accumulated postretirement benefit obligation was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	**$2,669**	$2,396
Service and interest costs	**242**	215

Workforce Reduction Program

In 1997, approximately one hundred employees of the Company accepted the terms of a workforce reduction plan. The cost incurred in connection with this voluntary plan was approximately $18 million. The MPSC approved the deferral and amortization of these program costs over a period not to exceed 60 months beginning no later than July 1998. As of December 31, 1999, the cost was fully amortized.

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 2000, 1999, and 1998 were $2.3 million, $2.2 million, and $2.1 million, respectively.

3. LITIGATION AND REGULATORY MATTERS

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power Company, Georgia Power Company and SCS. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously, and the Company's plants Watson and Greene County. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Savannah Electric and the Company as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August, 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted SCS's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include SCS in the new complaint. 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 unless such costs can be recovered through regulated rates.

Retail Rate Adjustment Plans

The Company's retail base rates are set under a Performance Evaluation Plan (PEP) approved by the MPSC in 1994. PEP was designed with the objective that the plan would reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low. PEP includes a mechanism for sharing rate adjustments based on the Company's ability to maintain low rates for customers and on the Company's performance as measured by three indicators that emphasize price and service to the customer. PEP provides for semiannual evaluations of the Company's performance-based return on investment. Any change in rates is limited to 2 percent of retail revenues per evaluation period. PEP will remain in effect until the MPSC modifies or terminates the plan. There were no PEP retail revenue changes for 2000, 1999, or 1998.

Environmental Compliance Overview Plan

The MPSC approved the Company's Environmental Compliance Overview Plan (ECO Plan) in 1992. The ECO Plan establishes procedures to facilitate the MPSC's overview of the Company's environmental strategy and provides for recovery of costs (including costs of capital) associated with environmental projects approved by the MPSC. Under the ECO Plan, any increase in the annual revenue requirement is limited to 2 percent of retail revenues. However, the ECO Plan also provides for carryover of any amount over the 2 percent limit into the next year's revenue requirement. The Company conducts studies, when possible, to determine the extent of any required environmental remediation. Should such remediation be determined to be probable, reasonable estimates of costs to clean up such sites are developed and recognized in the financial statements. The Company recovers such costs under the ECO Plan as they are incurred, as provided for in the Company's 1995 ECO Plan Order. The Company filed its 2001 ECO Plan in January and, if approved as filed, it will result in a slight increase in customer prices.

Approval for New Capacity

In January 1998, the Company was granted a Certificate of Public Convenience and Necessity by the MPSC to build approximately 1,064 megawatts of combined cycle generation at the Company's Plant Daniel site, to be placed in service by June 2001. In December 1998, the Company requested approval to transfer the ownership rights under the certificate to Escatawpa Funding, Limited Partnership ("Escatawpa"), which will lease the facility to the Company (see Note 4, Financing and Commitments). In September 2000, the Company and the Mississippi Public Utilities Staff entered, and the MPSC in October 2000 approved, a new stipulation that modifies a January 1999 stipulation and order covering cost allocation. The 1999 stipulation and MPSC order would have excluded the new capacity from retail ratebase and would have assigned the Company's existing generating facilities entirely to the retail jurisdiction. The new stipulation and MPSC order allocates a pro-rata share of the new capacity along with the Company's existing generating capacity to the retail jurisdiction.

4. FINANCING AND COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, the costs of which are currently estimated to total $62 million in 2001, $60 million in 2002, and $69 million in 2003. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; revised load growth estimates; changes in environmental regulations; increasing costs of labor, equipment and materials; and cost of capital. Significant construction will continue related to transmission and distribution facilities, and the upgrading of generating plants.

Financing

In 1999, the Company signed an Agreement for Lease and a Lease Agreement with Escatawpa, that calls for the Company to design and construct, as agent for Escatawpa, a 1,064 megawatt natural gas combined cycle facility. It is anticipated that the total project will cost approximately $400 million, and upon project completion in mid 2001, the Company intends to lease the facility for an initial term of approximately 10 years. It is anticipated that the annual lease payments will approximate $32 million during the initial term.

Bank Credit Arrangements

At December 31, 2000, the Company had total committed credit agreements with banks for approximately $117 million. At year-end 2000, the unused portion of these committed credit agreements was approximately $117 million. These credit agreements expire at various dates in 2001. Some of these agreements allow short-term borrowings to be converted into term loans, payable in 12 equal quarterly installments, with the first installment due at the end of the first calendar quarter after the applicable termination date or at an earlier date at the Company's option. In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. At December 31, 2000, the Company had $56 million of short-term borrowings outstanding.

Assets Subject to Lien

The Company's mortgage indenture dated as of September 1, 1941, as amended and supplemented, which secures the first mortgage bonds issued by the Company, constitutes a direct first lien on substantially all of the Company's fixed property and franchises.

Lease Agreements

In 1984, the Company and Entergy Corp. (formerly Gulf States Utilities) entered into a forty-year transmission facilities agreement whereby Entergy began paying a use fee to the Company covering all expenses relative to ownership and operation and maintenance of a 500 kV line, including amortization of its original $57 million cost. For the three years ended 2000, use fees collected under this agreement, net of related expenses, amounted to approximately $3 million each year, and are included within Other Income in the Statements of Income.

In 1989, the Company entered into a twenty-two year operating lease agreement for the use of 495 aluminum railcars. In 1994, a second lease agreement for the use of 250 additional aluminum railcars was also entered into for twenty-two years. The Company has the option to purchase the 745 railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. In 1997, a third lease agreement for the use of 360 railcars was also entered into for three years, with a monthly renewal option for up to an additional nine months. All of these leases, totaling 1,105 railcars, were for the transport of coal to Plant Daniel.

Gulf Power, as joint owner of Plant Daniel, is responsible for one half of the lease cost. The Company's share (50%) of the leases, charged to fuel stock, was $2.1 million in 2000, $2.8 million in 1999, and $2.8 million in 1998. The Company's annual lease payments for 2001 through 2005 will average approximately $2.0 million and after 2005, lease payments total in aggregate approximately $14 million.

Fuel

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 fuel. In most cases, these contracts contain provisions for price escalations, minimum production levels, and other financial commitments.

Total estimated obligations at December 31, 2000 were as follows:

Year	Fuel (in millions)
2001	$ 294
2002	332
2003	313
2004	137
2005	95
2006 - 2024	131
Total commitments	$1,302

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

5. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own as tenants in common Units 1 and 2 at Plant Greene County located in Alabama. Additionally, the Company and Gulf Power own as tenants in common Units 1 and 2 at Plant Daniel located in Mississippi.

At December 31, 2000, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

Generating Plant	Total Capacity (Megawatts)	Percent Ownership	Company's Gross Investment (in thousands)	Accumulated Depreciation (in thousands)
Greene County Units 1 and 2	500	40%	$63,346	$32,762
Daniel Units 1 and 2	1,000	50%	$230,853	$115,472

The Company's share of plant operating expenses is included in the corresponding operating expenses in the Statements of Income.

6. LONG-TERM CAPACITY SALES AND LEASE AGREEMENTS

The Company and the other utility affiliates of Southern Company have long-term contractual agreements for the sale of capacity and energy to certain non-affiliated utilities located outside the system's service area. Because the energy is generally sold at cost under these agreements, profitability is primarily affected by revenues from capacity sales. The Company's capacity revenues under these agreements were not material during the periods reported.

During 2000, the Company entered into a 10 year capacity lease that begins in mid 2001. The minimum capacity lease revenue that the Company will receive will average approximately $21 million per year over the 10 year period.

7. INCOME TAXES

At December 31, 2000, the tax-related regulatory assets and liabilities were $14 million and $26 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 federal and state income tax provisions are shown below:

	2000	1999	1998
	(in thousands)		
Total provision for income taxes			
Federal --			
Current	**$28,934**	$33,379	$20,500
Deferred	**622**	(3,973)	9,442
	29,556	29,406	29,942
State --			
Current	**4,670**	4,881	2,544
Deferred	**130**	(170)	2,178
	4,800	4,711	4,722
Total	**$34,356**	$34,117	$34,664

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 t deferred tax assets and liabilities are as follows:

	2000	1999
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$151,278**	$154,698
Basis differences	**8,559**	8,967
Other	**24,136**	23,108
Total	**183,973**	186,773
Deferred tax assets:		
Other property basis differences	**17,147**	21,003
Pension and other benefits	**9,528**	9,608
Property insurance	**3,558**	3,419
Unbilled fuel	**5,727**	4,846
Other	**9,669**	11,071
Total	**45,629**	49,947
Net deferred tax liabilities	**138,344**	136,826
Portion included in current assets, net	**1,565**	2,738
Accumulated deferred income taxes in the Balance Sheets	**$139,909**	$139,564

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 $1.2 million in 2000, 1999, and 1998. At December 31, 2000, 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:

	2000	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.4**	3.4	3.3
Non-deductible book depreciation	**.6**	.7	.5
Other	**(1.5)**	(1.6)	(1.0)
Effective income tax rate	**37.5%**	37.5%	37.8%

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.

8. COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES

In February 1997, Mississippi Power Capital Trust I (Trust I), of which the Company owns all the common securities, issued $35 million of 7.75 percent mandatorily redeemable preferred securities. Substantially all of the assets of Trust I are $36 million aggregate principal amount of the Company's 7.75 percent junior subordinated notes due February 15, 2037.

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.

Trust I is a subsidiary of the Company, and accordingly is consolidated in the Company's financial statements.

9. LONG-TERM DEBT DUE WITHIN ONE YEAR

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

	2000	1999
	(in thousands)	
Bond improvement fund requirement	**$1,000**	$1,000
Less: Portion to be satisfied by certifying property additions	**1,000**	1,000
Cash sinking fund requirement	**-**	-
Current portion of other long-term debt	**-**	30,000
Pollution control bond cash sinking fund requirements	**20**	20
Total	**$20**	$30,020

The first mortgage bond improvement fund requirement is one percent of each outstanding series authenticated under the indenture of the Company prior to January 1 of each year, other than first mortgage bonds issued as collateral security for certain pollution control obligations. The requirement must be satisfied by June 1 of each year by depositing cash or reacquiring bonds, or by pledging additional property equal to 166-2/3 percent of such requirement.

10. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's first mortgage bond indenture and the corporate charter contain various common stock dividend restrictions. At December 31, 2000, approximately $118 million of retained earnings was restricted against the payment of cash dividends on common stock under the most restrictive terms of the mortgage indenture or corporate charter.

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for 2000 and 1999 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends On Preferred Stock
		(in thousands)	
March 2000	**$134,705**	**$18,593**	**$6,722**
June 2000	**176,028**	**28,130**	**12,232**
September 2000	**220,119**	**53,943**	**28,762**
December 2000	**156,750**	**21,904**	**7,256**
March 1999	$122,435	$18,122	$7,193
June 1999	158,590	31,289	14,953
September 1999	201,594	51,609	27,313
December 1999	150,385	18,736	5,350

The Company's business is influenced by seasonal weather conditions and the timing of rate changes.

SELECTED FINANCIAL AND OPERATING DATA 1996-2000
Mississippi Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)*	**$687,602**	$633,004	$595,131	$543,588	$544,029
Net Income after Dividends on Preferred Stock (in thousands)	**$54,972**	$54,809	$55,105	$54,010	$52,723
Cash Dividends on Common Stock (in thousands)	**$54,700**	$56,100	$51,700	$49,400	$43,900
Return on Average Common Equity (percent)	**13.80**	14.00	14.15	14.00	13.90
Total Assets (in thousands)	**$1,275,071**	$1,251,136	$1,189,605	$1,166,829	$1,142,327
Gross Property Additions (in thousands)	**$81,211**	$75,888	$68,231	$55,375	$61,314
Capitalization (in thousands):					
Common stock equity	**$404,898**	$391,968	$391,231	$387,824	$383,734
Preferred stock	**31,809**	31,809	31,809	31,896	74,414
Company obligated mandatorily redeemable preferred securities	**35,000**	35,000	35,000	35,000	-
Long-term debt	**370,511**	321,802	292,744	291,665	326,379
Total (excluding amounts due within one year)	**$842,218**	$780,579	$750,784	$746,385	$784,527
Capitalization Ratios (percent):					
Common stock equity	**48.1**	50.2	52.1	52.0	48.9
Preferred stock	**3.8**	4.1	4.2	4.3	9.5
Company obligated mandatorily redeemable preferred securities	**4.2**	4.5	4.7	4.7	-
Long-term debt	**43.9**	41.2	39.0	39.0	41.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**Aa3**	Aa3	Aa3	Aa3	Aa3
Standard and Poor's	**A+**	AA-	AA-	AA-	A+
Fitch	**AA-**	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**a1**	a1	a1	a1	a1
Standard and Poor's	**BBB+**	A-	A	A	A
Fitch	**A**	A	A+	A+	A+
Customers (year-end):					
Residential	**158,253**	157,592	156,530	156,650	154,630
Commercial	**32,372**	31,837	31,319	31,667	30,366
Industrial	**517**	546	587	642	639
Other	**206**	202	200	200	200
Total	**191,348**	190,177	188,636	189,159	185,835
Employees (year-end):	**1,319**	1,328	1,230	1,245	1,363

* 1999 data includes the true-up of the unbilled revenue estimates.

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Mississippi Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)*:					
Residential	**$ 170,729**	$159,945	$157,642	$138,608	$137,055
Commercial	**163,552**	153,936	145,677	134,208	131,734
Industrial	**159,705**	151,244	135,039	140,233	141,324
Other	**4,565**	4,309	4,209	4,193	4,013
Total retail	**498,551**	469,434	442,567	417,242	414,126
Sales for resale - non-affiliates	**145,931**	131,004	121,225	105,141	99,596
Sales for resale - affiliates	**27,915**	19,446	18,285	10,143	21,830
Total revenues from sales of electricity	**672,397**	619,884	582,077	532,526	535,552
Other revenues	**15,205**	13,120	13,054	11,062	8,477
Total	**$687,602**	$633,004	$595,131	$543,588	$544,029
Kilowatt-Hour Sales (in thousands)*:					
Residential	**2,286,143**	2,248,255	2,248,915	2,039,042	2,079,611
Commercial	**2,883,197**	2,847,342	2,623,276	2,407,520	2,315,860
Industrial	**4,376,171**	4,407,445	3,729,166	3,981,875	3,960,243
Other	**41,153**	40,091	39,772	40,508	39,297
Total retail	**9,586,664**	9,543,133	8,641,129	8,468,945	8,395,011
Sales for resale - non-affiliates	**3,674,621**	3,256,175	3,157,837	2,895,182	2,726,993
Sales for resale - affiliates	**452,611**	539,939	552,142	478,884	693,510
Total	**13,713,896**	13,339,247	12,351,108	11,843,011	11,815,514
Average Revenue Per Kilowatt-Hour (cents)*:					
Residential	**7.47**	7.11	7.01	6.80	6.59
Commercial	**5.67**	5.41	5.55	5.57	5.69
Industrial	**3.65**	3.43	3.62	3.52	3.57
Total retail	**5.20**	4.92	5.12	4.93	4.93
Sales for resale	**4.21**	3.96	3.76	3.42	3.55
Total sales	**4.90**	4.65	4.71	4.50	4.53
Residential Average Annual Kilowatt-Hour Use Per Customer *	**14,445**	14,301	14,376	13,132	13,469
Residential Average Annual Revenue Per Customer *	**$1,078.76**	$1,017.42	$1,007.68	$892.68	$887.66
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,086**	2,086	2,086	2,086	2,086
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,305**	2,125	1,740	1,922	2,030
Summer	**2,593**	2,439	2,339	2,209	2,117
Annual Load Factor (percent)	**59.3**	59.6	58.0	59.1	60.7
Plant Availability Fossil-Steam (percent):	**92.6**	91.0	90.0	92.4	91.8
Source of Energy Supply (percent):					
Coal	**67.8**	69.4	66.5	70.5	70.4
Oil and gas	**13.5**	15.9	14.5	12.5	12.0
Purchased power -					
From non-affiliates	**7.7**	6.2	8.0	3.0	6.5
From affiliates	**11.0**	8.5	11.0	14.0	11.1
Total	**100.0**	100.0	100.0	100.0	100.0

* 1999 data includes the true-up of the unbilled revenue estimates.

SAVANNAH ELECTRIC AND POWER COMPANY

FINANCIAL SECTION

The management of Savannah Electric and 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 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 audit committee of the board of directors, composed of five independent directors who are not employees, provides a broad overview of management's financial reporting and control functions. Periodically, this committee meets with management, the internal auditors and the independent public accountants to ensure that these groups are fulfilling their obligations and to discuss auditing, internal controls and financial reporting matters. The internal auditors and the independent public accountants have access to the members of the audit committee 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 Savannah Electric and Power Company in conformity with accounting principles generally accepted in the United States.

G. Edison Holland, Jr.
President
and Chief Executive Officer

K. R. Willis
Vice President,
Treasurer, Chief Financial Officer
and Assistant Secretary

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Savannah Electric and Power Company:

We have audited the accompanying balance sheets and statements of capitalization of Savannah Electric and Power Company (a Georgia corporation and a wholly owned subsidiary of Southern Company) as of December 31, 2000 and 1999, 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, 2000. 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 II-179 through II-193) referred to above present fairly, in all material respects, the financial position of Savannah Electric and Power Company as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

RESULTS OF OPERATIONS

Earnings

Savannah Electric and Power Company's net income after dividends on preferred stock for 2000 totaled $23.0 million, representing no significant change from the prior year.

In 1999, earnings were $23.1 million, representing a $0.6 million, or 2.4 percent decrease from the prior year. This was principally due to lower non-operating revenues.

Revenues

Total operating revenues for 2000 were $295.7 million, reflecting a 17.5 percent increase when compared to 1999. The following table summarizes the factors affecting operating revenues for the past two years:

	Amount 2000	Increase (Decrease) From Prior Year 2000	1999
	(in thousands)		
Retail –			
Base Revenues	$161,807	$ 9,272	$ 376
Fuel cost recovery and other	120,815	31,085	(438)
Total retail	282,622	40,357	(62)
Sales for resale –			
Non-affiliates	4,748	1,353	(1,153)
Affiliates	4,974	823	1,135
Total sales for resale	9,722	2,176	(18)
Other operating revenues	3,374	1,591	(2,781)
Total operating revenues	$295,718	$44,124	$(2,861)
Percent change		17.5%	(1.1)%

Retail revenues increased 16.7 percent or $40.4 million in 2000 as compared to 1999. The primary contributors to the increase were continued growth in the Company's service territory, the positive impact of weather on energy sales, and an increase in fuel revenues.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Under these fuel recovery provisions, fuel revenues generally equal fuel expenses--including the fuel component of purchased energy--and do not affect net income. However, cash flow is affected by the economic loss from untimely recovery of these receivables. The Company currently plans to make a filing with the Georgia Public Service Commission (GPSC) in early 2001 to establish a new fuel rate in order to better reflect current fuel cost and to collect the current under-recovered balance.

Revenues from sales to utilities outside the service area under long-term contracts consist of capacity and energy components. Revenues from these sales were not material to the financial statements.

Sales to affiliated companies within the Southern electric system vary from year to year depending on demand and the availability and cost of generating resources at each company. These energy sales do not have a significant impact on earnings.

Energy Sales

Changes in revenues are influenced heavily by the amount of energy sold each year. Kilowatt-hour (KWH) sales for 2000 and the percent change by year were as follows:

	KWH 2000	Percent Change 2000	1999
	(in millions)		
Residential	1,671	5.8%	2.6%
Commercial	1,369	6.3	4.2
Industrial	800	12.2	(20.7)
Other	137	2.5	1.1
Total retail	3,977	7.1	(2.5)
Sales for resale –			
Non-affiliates	77	50.3	(3.3)
Affiliates	89	15.1	31.8
Total	4,143	7.8%	(2.0)%

Total retail energy sales in 2000 reflected increases in all customer classes. Industrial energy sales increased 12.2 percent reflecting the re-opening of an industrial facility under new ownership. Residential and commercial sales also increased reflecting weather related demand and customer growth.

In 1999, total retail energy sales were down by 2.5 percent from the prior year reflecting reduced energy sales of 20.7 percent to industrial customers due to the shut-down of one industrial customer's facilities in late 1998 and completed construction of a steam turbine unit by another industrial customer. These reductions were partially mitigated by increased energy sales of 2.6 percent and 4.2 percent to residential and commercial customers, respectively.

Expenses

Total operating expenses for 2000 were $245.0 million, an increase of $42.0 million from the prior year due primarily to increases in purchased power from both affiliates and non-affiliates and generation fuel expense. The increase in fuel expense is attributable to an increase in generation and higher fuel costs. Purchased power increased due principally to higher energy costs. Other operation expense was higher reflecting increased benefit expenses. Maintenance expense increased from 1999 reflecting higher power delivery and power generation maintenance costs to support improved customer reliability and unit availability, respectively. Depreciation and amortization increased reflecting additional depreciation charges related to the GPSC accounting order. See Note 3 to the financial statements for additional information on the GPSC's 1998 accounting order.

In 1999, total operating expenses were $203.0 million reflecting a slight increase of $1.4 million from the prior year. This increase was due primarily to increases in purchased power from non-affiliates and depreciation and amortization. Purchased power from non-affiliates increased due principally to higher demand for energy and increased costs associated with these power purchases. Depreciation and amortization increased reflecting additional depreciation charges related to the GPSC's accounting order.

Fuel and purchased power costs constitute the single largest expense for the Company. The mix of energy supply is determined primarily by system load, the unit cost of fuel consumed, and the availability of units.

The amount and sources of energy supply and the total average cost of energy supply were as follows:

	2000	1999	1998
Total energy supply (millions of KWHs)	**4,286**	4,039	4,182
Sources of energy supply (percent) --			
Coal	**52**	45	42
Oil	**2**	2	1
Gas	**5**	10	12
Purchased Power	**41**	43	45
Total average cost of energy supply (cents)	**3.09**	2.44	2.35

Effects of Inflation

The Company is subject to rate regulation and income tax laws that are based on the recovery of 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 trust preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed.

Future Earnings Potential

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from energy sales growth to a less regulated, more competitive environment.

The Company currently operates as a vertically integrated utility providing electricity to customers within the traditional service area of southeastern Georgia. Prices for electricity provided by the Company to retail customers are set by the GPSC. Prices for electricity relating to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power are set by the Federal Energy Regulatory Commission (FERC).

Future earnings in the near term will depend upon growth in energy sales, which 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.

Georgia Power is currently constructing two 566 megawatt combined cycle units at Plant Wansley to begin operation in 2002. The GPSC has certified the Company's purchase of capacity from these units to serve its retail customers for approximately seven years.

The electric utility industry in the United States is currently undergoing a period of dramatic change 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 the Company's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build cogeneration plants for industrial and commercial customers and sell energy generation to other utilities. Also, electricity sales for resale rates are affected by wholesale transmission access and numerous potential new energy suppliers, including power marketers and brokers. The Company is positioning the business to meet the challenge of this major change in the traditional practice of selling electricity.

Although the Energy Act does not permit retail customer access, it was a major catalyst for the current restructuring and consolidation taking place within the utility industry. Numerous federal and state initiatives are in varying stages to promote wholesale and retail competition. Among other things, these initiatives allow customers to choose their electricity provider. As these initiatives materialize, the structure of the utility industry could radically change. 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 the GPSC has held workshops to discuss retail competition and industry restructuring, there has been no proposed or enacted legislation to date in Georgia. Enactment would require numerous issues to be resolved, including significant ones relating to transmission pricing and recovery of costs. The GPSC continues its assessment of the range of potential stranded costs. The inability of the Company to recover its investments, including the regulatory assets described in Note 1 to the financial statements, could have a material adverse effect on the financial condition and results of operation. The Company is attempting to minimize or reduce its cost exposure.

Continuing to be a low-cost producer could provide opportunities to increase market share and profitability in markets that evolve with changing regulation. 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.

Rates to retail customers served by the Company are regulated by the GPSC. As part of the Company's rate settlement in 1992, it was informally agreed that the Company's earned rate of return on common equity should be 12.95 percent. In 1998, the GPSC issued a four-year accounting order settling its review of the Company's earnings. See Note 3 to the financial statements for additional information.

On December 20, 1999, FERC issued its final rule on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. After participating in regional conferences with customers and other members of the public to discuss the formation of RTOs, utilities were required to make a filing. On October 16, 2000, Southern Company and its integrated utility subsidiaries, including the Company, filed with FERC a proposal for the creation of an RTO. The proposal is for the formation of a for-profit company that would have control of the bulk power transmission system of Southern Company and any other participating utilities. Participants would have the option to maintain their ownership, divest, sell, or lease their assets to the proposed RTO. If the FERC accepts the proposal as filed, the creation of an RTO is not expected to have a material impact on Southern Company's financial statements. The outcome of this matter cannot now be determined.

The Energy Act amended the Public Utility Holding Company Act of 1935 (PUCHA) to allow holding companies to form exempt wholesale generators to sell power largely free of regulation under PUCHA. These entities are able to own and operate power generating facilities and sell power to affiliates--under certain restrictions.

Southern Company is aggressively working to maintain and expand its share of wholesale sales in the southeastern power markets. In January 2001, Southern Company announced formation of a new subsidiary--Southern Power Company. The new subsidiary will own, manage, and finance wholesale generating assets in the Southeast. Energy from its assets will be marketed to wholesale customers under the Southern Company name.

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 under "Environmental Matters."

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. In the event that a portion of the Company's operations 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 Standard

In June 2000, FASB issued Statement No. 138, an amendment of Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. Statement No. 133, as amended, establishes accounting and reporting standards for derivative instruments and for hedging activities. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value, and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

The Company enters into commodity related forward contracts to limit exposure to changing prices on electricity purchases and sales.

Substantially all of the Company's bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet the normal purchase and sale exception and the related contracts will continue to be accounted for under the accrual method. Certain of these instruments qualify as cash flow hedges resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness will be recognized currently in net income. However, others will be required to be marked to market through current period income.

The Company adopted Statement No. 133 effective January 1, 2001. The impact on net income was immaterial to the Company. The application of the new rules is still evolving and further guidance from FASB is expected, which could further impact the Company's financial statements. Also, as wholesale energy markets mature, future transactions could result in more volatility in net income and comprehensive income.

FINANCIAL CONDITION

Overview

The principal change in the Company's financial condition in 2000 was the addition of $27.3 million to utility plant. The funds needed for gross property additions are currently provided from operating activities, principally from earnings and non-cash charges to income such as depreciation and deferred income taxes and from financing activities. See Statements of Cash Flows for additional information.

Exposure to Market Risks

Due to cost-based regulation, the Company has limited exposure to market volatility in interest rate, 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. At December 31, 2000, exposure from these activities was not material to the Company's financial statements. Also, based on the Company's overall interest rate exposure at December 31, 2000, a near-term 100 basis point change in interest rates would not materially affect the financial statements.

Capital Structure

As of December 31, 2000, the Company's capital structure consisted of 52.7 percent common stockholders' equity, 12.1 percent trust preferred securities, and 35.2 percent long-term debt, excluding amounts due within one year. The Company's long-term financial objective for capitalization ratios is to maintain a capital structure of common stockholders' equity at 48 percent, preferred securities at 10 percent and debt at 42 percent.

Maturities and retirements of long-term debt were $0.4 million in 2000, $16.2 million in 1999, and $30.4 million in 1998.

Included in the 1999 maturities and retirements is the purchase by the Company of all $15 million outstanding of its 7 7/8% Series First Mortgage Bonds due May 1, 2025.

The composite interest rates and dividend rates for the years 1998 through 2000 as of year-end were as follows:

	2000	1999	1998
Composite interest rates on long-term debt	**6.6%**	6.4%	6.5%
Trust preferred securities dividend rate	**6.9%**	6.9%	6.9%

Capital Requirements for Construction

The Company's projected construction expenditures for the next three years total $95.9 million ($32.5 million in 2001, $31.5 million in 2002, and $31.9 million in 2003). Actual construction costs may vary from this estimate because of factors such as changes in: business conditions; environmental 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. Construction and upgrading of new and existing transmission and distribution facilities and upgrading of generating plants will be continuing.

Other Capital Requirements

In addition to the funds needed for the construction program, approximately $51.8 million will be needed by the end of 2003 for maturities of long-term debt and present sinking fund requirements.

Environmental Matters

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 Southern Company's integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously and the Company's Plant Kraft. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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 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.

In November 1990, the Clean Air Act Amendments of 1990 (Clean Air Act) were signed into law. Title IV of the Clean Air Act--the acid rain compliance provision of the law--significantly affected the Company and other subsidiaries of Southern Company. Specific reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995 and some 50 generating units of Southern Company were brought into compliance with Phase I requirements.

Southern Company achieved Phase I sulfur dioxide compliance at the affected plants by switching to low-sulfur coal, which required some equipment upgrades. The construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions compliance totaled approximately $2 million for Savannah Electric.

Phase II sulfur dioxide compliance was required in 2000. Southern Company used emission allowances and fuel switching to comply with Phase II requirements. No significant dollars for Phase II compliance have been spent by Savannah Electric.

A significant portion of costs related to the acid rain and ozone non-attainment provisions of the Clean Air Act is expected to be recovered through existing ratemaking provisions. However, there can be no assurance that all Clean Air Act costs will be recovered.

In July 1997, the EPA revised the national ambient air quality standards for ozone and particulate matter. This revision made the standards significantly more stringent. In the subsequent litigation of these standards, the U.S. Supreme Court recently dismissed certain challenges but found the EPA's implementation program for the new ozone standard unlawful and remanded it to the EPA. In addition, the Federal District of Columbia Circuit Court of Appeals will address other legal challenges to these standards in mid-2001. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued the final regional nitrogen oxide reduction rules to the states for implementation. Compliance is required by May 31, 2004. The final rule affects 21 states, including Georgia. This rule remains involved in litigation in the federal courts.

In December 2000, the EPA completed its utility studies for mercury and other hazardous air pollutants (HAPS) and issued a determination that an emission control program for mercury and, perhaps, other HAPS is warranted. The program is to be developed over the next four years under the Maximum Achievable Control Technology (MACT) provisions of the Clean Air Act. This determination is being challenged in the courts. In January 2001, the EPA proposed guidance for the determination of Best Available Retrofit Technology (BART) emission controls under the Regional Haze Regulations. Installation of BART controls is expected to take place around 2010. Litigation of the BART rules is probable in the near future.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide, sulfur dioxide, mercury, and other HAPS emissions from fossil-fired generating facilities and other industries in these states. Additional compliance costs and capital expenditures resulting from the implementation of these rules and standards cannot be determined until the results of legal challenges are known, and the states have adopted their final rules. Reviews by the new administration in Washington, D.C. add to the uncertainties associated with BART guidance and the MACT determination for mercury and other HAPS.

The EPA and state environmental regulatory agencies are reviewing and evaluating various other matters including: control strategies to reduce regional haze; limits on pollutant discharges to impaired waters; water intake restrictions; and hazardous waste disposal requirements. The impact of any new standards will depend on the development and implementation of applicable regulations.

The Company must comply with other environmental laws and regulations that cover the handling and disposal of hazardous waste. 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 costs and will recognize in the financial statements costs to clean up known sites.

Several major pieces of environmental legislation are being 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; and the Endangered Species Act. Changes to these laws could affect many areas of the Company's operations. The full impact of any such changes cannot be determined at this time.

Compliance with possible additional legislation related to global climate change, electromagnetic fields, and other environmental and health concerns could significantly affect the Company. The impact of new legislation--if any--will depend on the subsequent development and implementation of applicable regulations. In addition, the potential exists for liability as the result of lawsuits alleging damages caused by electromagnetic fields.

Sources of Capital

At December 31, 2000, the Company had $50.1 million of unused short-term and revolving credit arrangements with banks to meet its short-term cash needs and to provide additional interim funding for the Company's construction program. Revolving credit arrangements total $20 million, of which $10 million expires April 30, 2003 and $10 million expires December 31, 2003.

It is anticipated that the funds required for construction and other purposes, including compliance with environmental regulation, will be derived from sources similar to those used in the past. These sources were primarily from the issuances of first mortgage bonds, other long-term debt, and preferred stock, in addition to pollution control revenue bonds issued for the Company's benefit by public authorities, to meet long-term external financing requirements. Recently, the Company's financings have consisted of unsecured debt and trust preferred securities. The Company is required to meet certain earnings coverage requirements specified in its mortgage indenture and corporate charter to issue new first mortgage bonds and preferred stock. The Company's coverage ratios are sufficiently high to permit, at present interest rate levels, any foreseeable security sales. There are no restrictions on the amount of unsecured indebtedness allowed. The amount of securities which the Company will be permitted to issue in the future will depend upon market conditions and other factors prevailing at that time.

Cautionary Statement Regarding Forward-Looking Information

This Annual Report includes forward-looking statements in addition to historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "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 extent and timing of the entry of additional competition in the markets of the Company; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options that may be pursued by the Company; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the ability of the Company to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time by the Company with the SEC.

STATEMENTS OF INCOME
For the Years Ended December 31, 2000, 1999, and 1998
Savannah Electric and Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Revenues:			
Retail sales	**$282,622**	$242,265	$242,327
Sales for resale --			
Non-affiliates	**4,748**	3,395	4,548
Affiliates	**4,974**	4,151	3,016
Other revenues	**3,374**	1,783	4,564
Total operating revenues	**295,718**	251,594	254,455
Operating Expenses:			
Operation --			
Fuel	**57,177**	50,530	53,021
Purchased power --			
Non-affiliates	**25,229**	14,398	9,460
Affiliates	**50,111**	33,398	35,687
Other	**54,829**	51,802	50,321
Maintenance	**19,334**	16,333	18,711
Depreciation and amortization (Note 3)	**25,240**	23,841	22,032
Taxes other than income taxes	**13,116**	12,690	12,342
Total operating expenses	**245,036**	202,992	201,574
Operating Income	**50,682**	48,602	52,881
Other Income (Expense):			
Interest income	**252**	169	384
Other, net	**1,086**	798	(432)
Earnings Before Interest and Income Taxes	**52,020**	49,569	52,833
Interest and Other:			
Interest expense, net	**12,737**	11,938	11,855
Distributions on preferred securities of subsidiary	**2,740**	2,740	167
Total interest and other, net	**15,477**	14,678	12,022
Earnings Before Income Taxes	**36,543**	34,891	40,811
Income taxes (Note 5)	**13,574**	11,808	15,101
Net Income	**22,969**	23,083	25,710
Dividends on Preferred Stock	**-**	-	2,066
Net Income After Dividends on Preferred Stock	**$ 22,969**	$ 23,083	$ 23,644

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2000, 1999, and 1998
Savannah Electric and Power Company 2000 Annual Report

	2000	1999	1998
		(in thousands)	
Operating Activities:			
Net income	**$22,969**	$23,083	$25,710
Adjustments to reconcile net income			
to net cash provided from operating activities –			
Depreciation and amortization	**26,639**	25,454	23,531
Deferred income taxes and investment tax credits, net	**728**	(3,353)	7,011
Other, net	**3,835**	(47)	(89)
Changes in certain current assets and liabilities --			
Receivables, net	**(23,260)**	(5,999)	(9,875)
Fossil fuel stock	**(31)**	(2,125)	221
Materials and supplies	**(542)**	(1,906)	484
Accounts payable	**8,881**	1,133	470
Other	**(4,674)**	1,731	(4,859)
Net cash provided from operating activities	**34,545**	37,971	42,604
Investing Activities:			
Gross property additions	**(27,290)**	(29,833)	(18,071)
Other	**(1,835)**	(1,715)	1,617
Net cash used for investing activities	**(29,125)**	(31,548)	(16,454)
Financing Activities:			
Increase in notes payable, net	**11,100**	34,300	-
Proceeds --			
Other long-term debt	-	-	30,000
Preferred securities	-	-	40,000
Capital contributions from parent company	**1,478**	1,099	-
Retirements --			
First mortgage bonds	-	(15,800)	(30,000)
Other long-term debt	**(251)**	(481)	(478)
Preferred stock	-	-	(35,000)
Payment of preferred stock dividends	-	-	(2,556)
Payment of common stock dividends	**(24,300)**	(25,200)	(23,500)
Other	-	250	(4,798)
Net cash used for financing activities	**(11,973)**	(5,832)	(26,332)
Net Change in Cash and Cash Equivalents	**(6,553)**	591	(182)
Cash and Cash Equivalents at Beginning of Period	**6,553**	5,962	6,144
Cash and Cash Equivalents at End of Period	**$ -**	$ 6,553	$ 5,962
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$13,329**	$14,212	$12,198
Income taxes (net of refunds)	**19,939**	12,647	9,666

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2000 and 1999
Savannah Electric and Power Company 2000 Annual Report

Assets	2000	1999
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ -	$ 6,553
Receivables --		
Customer accounts receivable	28,189	20,752
Unrecovered retail fuel clause revenue	39,632	21,089
Other accounts and notes receivable	1,412	3,505
Affiliated companies	738	1,195
Accumulated provision for uncollectible accounts	(407)	(237)
Fossil fuel stock, at average cost	7,140	7,109
Materials and supplies, at average cost	8,944	8,402
Prepaid taxes	8,651	2,434
Other	377	435
Total current assets	94,676	71,237
Property, Plant, and Equipment:		
In service (Note 7)	829,270	804,096
Less accumulated provision for depreciation	382,030	360,639
	447,240	443,457
Construction work in progress	6,782	6,561
Total property, plant, and equipment	454,022	450,018
Other Property and Investments	2,066	1,506
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 5)	12,404	16,063
Cash surrender value of life insurance for deferred compensation plans	17,954	16,305
Prepaid pension costs (Note 2)	-	1,201
Debt expense, being amortized	3,003	3,155
Premium on reacquired debt, being amortized	7,575	8,385
Other	2,527	2,348
Total deferred charges and other assets	43,463	47,457
Total Assets	$594,227	$570,218

The accompanying notes are an integral part of these balance sheets.

BALANCE SHEETS
At December 31, 2000 and 1999
Savannah Electric and Power Company 2000 Annual Report

Liabilities and Stockholder's Equity	2000	1999
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 7)	**$ 30,698**	$ 704
Notes payable	**45,400**	34,300
Accounts payable --		
Affiliated	**16,153**	4,632
Other	**7,738**	11,118
Customer deposits	**5,696**	5,426
Taxes accrued --		
Income taxes	**3,450**	3,046
Other	**1,435**	3,013
Interest accrued	**4,541**	3,237
Vacation pay accrued	**2,276**	2,142
Other	**7,973**	5,742
Total current liabilities	**125,360**	73,360
Long-term debt (See accompanying statements)	**116,902**	147,147
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 5)	**79,756**	80,318
Deferred credits related to income taxes (Note 5)	**16,038**	19,687
Accumulated deferred investment tax credits (Note 5)	**10,616**	11,280
Deferred compensation plans	**11,968**	10,624
Employee benefits provisions (Note 2)	**8,127**	7,805
Other	**10,466**	5,150
Total deferred credits and other liabilities	**136,971**	134,864
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes (See accompanying statements) (Note 6)	**40,000**	40,000
Common stockholder's equity (See accompanying statements)	**174,994**	174,847
Total Liabilities and Stockholder's Equity	**$594,227**	$570,218

The accompanying notes are an integral part of these balance sheets.

STATEMENTS OF CAPITALIZATION
At December 31, 2000 and 1999
Savannah Electric and Power Company 2000 Annual Report

		2000	1999	2000	1999
			(in thousands)		*(percent of total)*
Long-Term Debt (Note 7):					
First mortgage bonds --					
Maturity	Interest Rates				
July 1, 2003	6.375%	**$ 20,000**	$ 20,000		
May 1, 2006	6.90%	**20,000**	20,000		
July 1, 2023	7.40%	**24,200**	24,200		
Total first mortgage bonds		**64,200**	64,200		
Long-term notes payable --					
6.88% due June 1, 2001		**10,000**	10,000		
6.625% due March 17, 2015		**30,000**	30,000		
Adjustable rates (6.71% to 6.86% at 1/1/01) due 2001		**20,000**	20,000		
Total long-term notes payable		**60,000**	60,000		
Other long-term debt --					
Pollution control revenue bonds --					
Non-collateralized:					
Variable rates (5.10% at 1/1/01) due 2016-2037		**17,955**	17,955		
Total other long-term debt		**17,955**	17,955		
Capitalized lease obligations		**5,445**	5,696		
Total long-term debt (annual interest requirement -- $9.8 million)		**147,600**	147,851		
Less amount due within one year (Note 7)		**30,698**	704		
Long-term debt excluding amount due within one year		**116,902**	147,147	**35.2%**	40.7%
Company Obligated Mandatorily Redeemable Preferred Securities (Note 6):					
$25 liquidation value -- 6.85%		**40,000**	40,000		
Total (annual distribution requirement -- $2.7 million)		**40,000**	40,000	**12.1**	11.0
Common Stockholder's Equity (Note 8):					
Common stock, par value $5 per share --					
Authorized - 16,000,000 shares					
Outstanding - 10,844,635 shares in 2000 and 1999					
Par value		**54,223**	54,223		
Paid-in capital		**11,265**	9,787		
Retained earnings		**109,506**	110,837		
Total common stockholder's equity		**174,994**	174,847	**52.7**	48.3
Total Capitalization		**$331,896**	$361,994	**100.0%**	100.0%

The accompanying notes are an integral part of these statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2000, 1999, and 1998
Savannah Electric and Power Company 2000 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Total
	(in thousands)			
Balance at January 1, 1998	$54,223	$8,688	$112,720	$175,631
Net income after dividends on preferred stock	-	-	23,644	23,644
Cash dividends on common stock	-	-	(23,500)	(23,500)
Other	-	-	90	90
Balance at December 31, 1998	54,223	8,688	112,954	175,865
Net income after dividends on preferred stock	-	-	23,083	23,083
Capital contributions from parent company	-	1,099	-	1,099
Cash dividends on common stock	-	-	(25,200)	(25,200)
Balance at December 31, 1999	54,223	9,787	110,837	174,847
Net income after dividends on preferred stock	-	-	**22,969**	**22,969**
Capital contributions from parent company	-	**1,478**	-	**1,478**
Cash dividends on common stock	-	-	**(24,300)**	**(24,300)**
Balance at December 31, 2000 (Note 8)	**$54,223**	**$11,265**	**$109,506**	**$174,994**

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Savannah Electric and Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of five integrated Southeast utilities, a system service company (SCS), Southern Communications Services (Southern LINC), Southern Company Energy Solutions, Southern Nuclear Operating Company (Southern Nuclear), Mirant Corporation--formerly Southern Energy, Inc.--and other direct and indirect subsidiaries. The integrated Southeast utilities provide electric service in four states. Contracts among the integrated Southeast utilities--related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power--are regulated by the Federal Energy Regulatory Commission (FERC) and/or the Securities and Exchange Commission. SCS provides, at cost, specialized services to Southern Company and subsidiary companies. Southern LINC provides digital wireless communications services to the integrated Southeast utilities and also markets these services to the public within the Southeast. Southern Company Energy Solutions develops new business opportunities related to energy products and services. Southern Nuclear provides services to Southern Company's nuclear power plants. Mirant acquires, develops, builds, owns and operates power production and delivery facilities, and provides a broad range of energy-related services to utilities and industrial companies in selected countries around the world. Mirant businesses include independent power projects, integrated utilities, a distribution company, and energy trading and marketing businesses outside the southeastern United States.

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 also is subject to regulation by the FERC and the Georgia Public Service Commission (GPSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by the GPSC. 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 has been reclassified to conform with the current year presentation.

Related-Party Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at cost: general and design engineering, purchasing, accounting and statistical, finance and treasury, tax, information resources, marketing, auditing, insurance and pension, human resources, systems and procedures, and other administrative services with respect to business and operations and power pool operations. Costs for these services amounted to $15.1 million, $16.0 million, and $15.3 million during 2000, 1999, and 1998, respectively.

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 to the Company 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:

	2000	1999
	(in thousands)	
Deferred income tax charges	**$12,404**	$ 16,063
Premium on reacquired debt	**7,575**	8,385
Deferred income tax credits	**(16,038)**	(19,687)
Storm damage reserves	**(2,733)**	(1,392)
Accelerated depreciation	**(5,500)**	(3,000)
Total	**$ (4,292)**	$ 369

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 value.

Revenues and Fuel Costs

The Company currently operates as a vertically integrated utility providing electricity to retail customers within its traditional service area of southeastern Georgia 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, 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 rates.

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 averaged less than 1 percent of revenues.

In 2000, the GPSC approved an increase of slightly over one-third of a cent per kilowatt hour in the Company's fuel cost recovery rate. An increase of slightly over three-tenths of a cent per kilowatt-hour was approved in 1999.

The Company currently plans to make a filing with the GPSC in early 2001 to establish a new fuel rate in order to better reflect current fuel costs and to collect the current under-recovered balance.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.0 percent in 2000 and 1999, and 2.9 percent in 1998. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost--together with the cost of removal, less salvage--is charged to the accumulated provision for 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 removal of certain facilities. In 1998, 1999 and 2000, the Company recorded accelerated depreciation of $1.0 million, $2.0 million and $2.5 million respectively, in accordance with the GPSC's 1998 rate order. See Note 3 to the financial statements for more information.

Income Taxes

The Company, which is included in the consolidated federal income tax return filed by Southern 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)

AFUDC represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new 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. The composite rates used by the Company to calculate AFUDC were 6.87 percent in 2000, 6.26 percent in 1999 and 8.00 percent in 1998.

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 maintenance, repairs, and replacement of minor items of property is charged to maintenance expense. The cost of replacements of property exclusive of minor items of property is capitalized.

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 costs 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.

Financial Instruments

The Company's financial instruments for which the carrying amounts did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2000	**$142**	**$140**
At December 31, 1999	$142	$136
Trust preferred securities:		
At December 31, 2000	**$40**	**$36**
At December 31, 1999	$40	$31

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

2. RETIREMENT BENEFITS

The Company has defined benefit, trusteed, non-contributory pension plans that cover substantially all employees. The Company provides certain medical care and life insurance benefits for retired employees. Substantially all these employees may become eligible for such benefits when they retire. The Company funds trusts to the extent required by the GPSC. The measurement date for plan assets and obligations is September 30 of each year.

In late 2000, the Company adopted several pension and postretirement benefit plan changes that had the effect of increasing benefits to both current and future retirees. The effects of these changes will be to increase annual pension and postretirement benefits costs by approximately $0.5 million and $0.3 million, respectively.

Pension Plans

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

	Projected Benefit Obligations	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$59,961**	$59,207
Service cost	**1,742**	1,746
Interest cost	**4,380**	3,893
Benefits paid	**(3,210)**	(3,414)
Actuarial (gain) loss and employee transfers	**1,802**	(1,856)
Amendments	**219**	385
Balance at end of year	**$64,894**	$59,961

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$54,480**	$49,630
Actual return on plan assets	**10,493**	8,168
Benefits paid	**(3,210)**	(3,414)
Employee transfers	**117**	96
Balance at end of year	**$61,880**	$54,480

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

	2000	1999
	(in thousands)	
Funded status	**$(3,014)**	$(5,481)
Unrecognized transition obligation	**89**	178
Unrecognized prior service cost	**2,929**	2,996
Unrecognized net loss (gain)	**(1,127)**	3,508
(Accrued liability) prepaid asset recognized in the Balance Sheets	**$(1,123)**	$1,201

Components of the plans' net periodic cost were as follows:

	2000	1999	1998
	(in thousands)		
Service cost	**$1,742**	$1,746	$1,495
Interest cost	**4,380**	3,893	3,806
Expected return on plan assets	**(4,174)**	(4,063)	(3,992)
Recognized net loss	**-**	152	2
Net amortization	**376**	352	334
Net pension cost	**$2,324**	$2,080	$1,645

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	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$22,904**	$23,556
Service cost	**376**	404
Interest cost	**1,865**	1,549
Benefits paid	**(963)**	(756)
Actuarial gain and employee transfers	**(1,367)**	(1,849)
Amendments	**3,309**	-
Balance at end of year	**$26,124**	$22,904

	Plan Assets	
	2000	1999
	(in thousands)	
Balance at beginning of year	**$5,254**	$3,803
Actual return on plan assets	**606**	476
Employer contributions	**2,013**	1,731
Benefits paid	**(963)**	(756)
Balance at end of year	**$6,910**	$5,254

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

	2000	1999
	(in thousands)	
Funded status	**$(19,214)**	$(17,650)
Unrecognized transition obligation	**5,925**	6,419
Unamortized prior service cost	**3,185**	-
Unrecognized net loss	**1,701**	3,311
Fourth quarter contributions	**1,493**	1,336
Accrued liability recognized in the Balance Sheets	**$(6,910)**	$(6,584)

Components of the postretirement plans' net periodic cost were as follows:

	2000	1999	1998
	(in thousands)		
Service cost	**$ 376**	$ 404	$ 348
Interest cost	**1,865**	1,549	1,528
Expected return on plan assets	**(429)**	(345)	(276)
Recognized net loss	**66**	152	104
Net amortization	**618**	494	494
Net postretirement cost	**$2,496**	$2,254	$2,198

The weighted average rates assumed in the actuarial calculations for both the pension and postretirement benefit plans were:

	2000	1999
Discount	**7.50%**	7.50%
Annual salary increase	**5.00**	5.00
Long-term return on plan assets	**8.50**	8.50

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 7.29 percent for 2000, decreasing gradually to 5.50 percent through the year 2005, 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, 2000 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	**$1,417**	**$1,598**
Service and interest costs	**110**	**140**

The Company has a supplemental retirement plan for certain executive employees. The plan is unfunded and payable from the general funds of the Company. The Company has purchased life insurance on participating executives, and plans to use these policies to satisfy this obligation.

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 2000, 1999, and 1998 were $0.9 million, $0.9 million, and $0.8 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

Environmental Litigation

On November 3, 1999, the EPA brought a civil action in the U.S. District Court against Alabama Power, Georgia Power, and the system service company. The complaint alleges violations of the prevention of significant deterioration and new source review provisions of the Clean Air Act with respect to five coal-fired generating facilities in Alabama and Georgia. 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 integrated Southeast utilities a notice of violation related to 10 generating facilities, which includes the five facilities mentioned previously and the Company's Plant Kraft. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation, and to add Gulf Power, Mississippi Power, and Savannah Electric as defendants. 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 had failed to secure necessary permits or install additional pollution equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted Alabama Power's motion to dismiss for lack of jurisdiction in Georgia and granted the system service company's motion to dismiss on the grounds that it neither owned nor operated the generating units involved in the proceedings. On January 12, 2001, the EPA re-filed its claims against Alabama Power in federal district court in Birmingham, Alabama. The EPA did not include the system service company in the new complaint. Southern Company believes that its integrated utilities 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 Regulatory Matters

Rates to retail customers served by the Company are regulated by the GPSC. As part of the Company's rate settlement in 1992, it was informally agreed that the Company's earned rate of return on common equity should be 12.95 percent.

In 1998, the GPSC approved a four-year accounting order for the Company. Under this order, the Company will reduce the electric rates of its small business customers by approximately $11 million over four years. The Company will also expense an additional $1.95 million in storm damage accruals and accrue an additional $8 million in depreciation on generating assets over the term of the order. The additional depreciation will be accumulated in a regulatory liability account to be available to mitigate any potential stranded costs. In addition, the Company has discretionary authority to provide up to an additional $0.3 million per year in storm damage accruals and up to an additional $4.0 million in depreciation expense over the four years. Total storm damages accrued under the order were $1.5 million in both 2000 and 1999 and $0.75 million in 1998. No discretionary depreciation was recorded in the last three years. Over the term of the order, the Company is precluded from asking for a rate increase except upon significant changes in economic conditions, new laws, or regulations. There is a quarterly monitoring of the Company's earnings performance.

4. COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, currently estimated to total $32.5 million in 2001, $31.5 million in 2002, and $31.9 million in 2003. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental regulations; increasing costs of labor, equipment, and materials; and changes in cost of capital. The Company does not have any traditional baseload generating plants under construction. However, construction related to new and upgrading of existing transmission and distribution facilities and the upgrading of generating plants will continue.

To the extent possible, the Company's construction program is expected to be financed from internal sources and from the issuance of additional long-term debt and capital contributions from Southern Company.

The amounts of long-term debt and trust preferred securities that can be issued in the future will be contingent on market conditions, the maintenance of adequate earnings levels, regulatory authorizations, and other factors.

Bank Credit Arrangements

At the end of 2000, unused credit arrangements with four banks totaled $50.1 million and expire at various times during 2001.

The Company has revolving credit arrangements of $20 million, of which $10 million expires April 30, 2003 and $10 million expires December 31, 2003. One of these agreements allows short-term borrowings to be converted into term loans, payable in 12 equal quarterly installments, with the first installment due at the end of the first calendar quarter after the applicable termination date or at an earlier date at the Company's option.

In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments.

Assets Subject to Lien

As amended and supplemented, the Company's Indenture of Mortgage, which secures the first mortgage bonds issued by the Company, constitutes a direct first lien on substantially all of the Company's fixed property and franchises. A second lien for $10 million of bank debt is secured by a portion of the Plant Kraft property and a second lien for $34 million in bank notes is secured by a portion of the Plant McIntosh property.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into long-term commitments for the procurement of fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. The Company has fuel commitments of $44 million and $8 million for 2001 and 2002, respectively.

The company has entered into various long-term commitments for the purchase of electricity. Estimated total long-term obligations at December 31, 2000 were as follows:

Year	Commitments (in thousands)
2001	$ 0
2002	9,627
2003	13,245
2004	13,261
2005	13,277
2006 and beyond	53,283
Total commitments	$102,693

Operating Leases

The Company has rental agreements with various terms and expiration dates. Rental expenses totaled $0.4 million for 2000, $0.5 million for 1999, and $1.1 million for 1998.

At December 31, 2000, estimated future minimum lease payments for noncancelable operating leases were as follows:

	Rental Commitments
	(in thousands)
2001	$433
2002	433
2003	433
2004	433
2005	433
2006 and thereafter	$5,379

5. INCOME TAXES

At December 31, 2000, tax-related regulatory assets and liabilities were $12.4 million and $16.0 million, respectively. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2000	1999	1998
	(in thousands)		
Total provision for income taxes			
Federal –			
Currently payable	**$11,102**	$12,968	$ 6,763
Deferred	**75**	(3,329)	5,812
	11,177	9,639	12,575
State --			
Currently payable	**1,744**	2,193	1,327
Deferred	**653**	(24)	1,199
	2,397	2,169	2,526
Total	**$13,574**	$11,808	$15,101

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:

	2000	1999
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$76,901**	$76,282
Property basis differences	**5,904**	6,917
Other	**17,807**	12,031
Total	**100,612**	95,230
Deferred tax assets:		
Pension and other benefits	**9,744**	6,965
Other	**7,662**	5,777
Total	**17,406**	12,742
Net deferred tax liabilities	**83,206**	82,488
Portions included in current assets, net	**(3,450)**	(2,170)
Accumulated deferred income taxes in the Balance Sheets	**$79,756**	$80,318

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 $ 0.7 million in 2000, 1999 and 1998. At December 31, 2000, 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:

	2000	1999	1998
Federal statutory tax rate	**35%**	35%	35%
State income tax, net of federal income tax benefit	**4**	4	4
Other	**(2)**	(5)	(2)
Effective income tax rate	**37%**	34%	37%

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.

6. TRUST PREFERRED SECURITIES

In December 1998, Savannah Electric Capital Trust I, of which the Company owns all of the common securities, issued $40 million of 6.85% mandatorily redeemable preferred securities. Substantially all of the assets of the Trust are $40 million aggregate principal amount of the Company's 6.85% junior subordinated notes due December 31, 2028.

The Company considers that the mechanisms and obligations relating to the trust preferred securities, taken together, constitute a full and unconditional guarantee by the Company of payment obligations with respect to the preferred securities of Savannah Electric Capital Trust I.

Savannah Electric Capital Trust I is a subsidiary of the Company, and accordingly is consolidated in the Company's financial statements.

7. LONG-TERM DEBT AND LONG-TERM DEBT DUE WITHIN ONE YEAR

The Company's Indenture related to its First Mortgage Bonds is unlimited as to the authorized amount of bonds which may be issued, provided that required property additions, earnings and other provisions of such Indenture are met.

Maturities and retirements of long-term debt were $0.4 million in 2000, $16.2 million in 1999 and $30.4 million in 1998. Included in the 1999 maturities and retirements is the purchase by the Company of all $15 million outstanding of its 7 7/8% Series First Mortgage Bonds due May 1, 2025.

Assets acquired under capital leases are recorded as utility plant in service, and the related obligation is classified as other long-term debt. Leases are capitalized at the net present value of the future lease payments. However, for ratemaking purposes, these obligations are treated as operating leases, and as such, lease payments are charged to expense as incurred.

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

	2000	1999
	(in thousands)	
Bond sinking fund requirement	$ **642**	$650
Less:		
Portion to be satisfied by certifying property additions	**642**	650
Cash sinking fund requirement	**-**	-
Other long-term debt maturities	**30,698**	704
Total	**$30,698**	$704

The first mortgage bond improvement (sinking) fund requirements amount to 1 percent of each outstanding series of bonds authenticated under the Indenture prior to January 1 of each year, other than those issued to collateralize pollution control and other obligations. The requirements may be satisfied by depositing cash or reacquiring bonds, or by pledging additional property equal to 1 2/3 times the requirements.

The sinking fund requirements of first mortgage bonds were satisfied by certifying property additions in 2000 and by cash redemptions in 1999. It is anticipated that the 2001 requirement will be satisfied by certifying property additions. Sinking fund requirements and/or maturities through 2005 applicable to long-term debt are as follows: $30.7 million in 2001; $0.6 million in 2002; $20.5 million in 2003; $0.5 million in 2004; and $0.4 million in 2005.

8. COMMON STOCK DIVIDEND RESTRICTIONS

The Company's Indenture contains certain limitations on the payment of cash dividends on common stock. At December 31, 2000, approximately $68 million of retained earnings was restricted against the payment of cash dividends on common stock under the terms of the Indenture.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2000 and 1999 are as follows (in thousands):

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
March 2000	**$52,390**	**$ 6,583**	**$ 1,643**
June 2000	**72,780**	**14,100**	**6,287**
September 2000	**98,849**	**24,060**	**12,351**
December 2000	**71,699**	**5,939**	**2,688**
March 1999	$47,098	$ 5,315	$ 1,209
June 1999	61,692	12,173	5,268
September 1999	91,849	26,759	13,705
December 1999	50,955	4,355	2,901

The Company's business is influenced by seasonal weather conditions and a seasonal rate structure, among other factors.

The quarterly operating income information above has been reclassified to reflect the Company's current presentation of income tax expense.

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SELECTED FINANCIAL AND OPERATING DATA 1996-2000
Savannah Electric and Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands)	**$295,718**	$251,594	$254,455	$226,277	$234,074
Net Income after Dividends					
on Preferred Stock (in thousands)	**$22,969**	$23,083	$23,644	$23,847	$23,940
Cash Dividends					
on Common Stock (in thousands)	**$24,300**	$25,200	$23,500	$20,500	$19,600
Return on Average Common Equity (percent)	**13.13**	13.16	13.45	13.71	14.08
Total Assets (in thousands)	**$594,227**	$570,218	$555,799	$547,352	$544,900
Gross Property Additions (in thousands)	**$27,290**	$29,833	$18,071	$18,846	$28,950
Capitalization (in thousands):					
Common stock equity	**$174,994**	$174,847	$175,865	$175,631	$172,284
Preferred stock	**-**	-	-	35,000	35,000
Company obligated mandatorily					
redeemable preferred securities	**40,000**	40,000	40,000	-	-
Long-term debt	**116,902**	147,147	163,443	142,846	164,406
Total (excluding amounts due within one year)	**$331,896**	$361,994	$379,308	$353,477	$371,690
Capitalization Ratios (percent):					
Common stock equity	**52.7**	48.3	46.4	49.7	46.4
Preferred stock	**-**	-	-	9.9	9.4
Company obligated mandatorily					
redeemable preferred securities	**12.1**	11.0	10.5	-	-
Long-term debt	**35.2**	40.7	43.1	40.4	44.2
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+**	AA-	AA-	AA-	A+
Preferred Stock -					
Moody's	**a2**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	A-	A	A	A
Customers (year-end):					
Residential	**115,646**	112,891	110,437	109,092	106,657
Commercial	**15,727**	15,433	15,328	14,233	13,877
Industrial	**75**	67	63	64	65
Other	**444**	417	377	1,129	1,097
Total	**131,892**	128,808	126,205	124,518	121,696
Employees (year-end):	**554**	533	542	535	571

SELECTED FINANCIAL AND OPERATING DATA 1996-2000 (continued)
Savannah Electric and Power Company 2000 Annual Report

	2000	1999	1998	1997	1996
Operating Revenues (in thousands):					
Residential	**$129,520**	$112,371	$109,393	$ 96,587	$101,607
Commercial	**102,116**	88,449	86,231	78,949	80,494
Industrial	**40,839**	32,233	37,865	35,301	37,077
Other	**10,147**	9,212	8,838	8,621	8,804
Total retail	**282,622**	242,265	242,327	219,458	227,982
Sales for resale - non-affiliates	**4,748**	3,395	4,548	3,467	1,998
Sales for resale - affiliates	**4,974**	4,151	3,016	2,052	3,130
Total revenues from sales of electricity	**292,344**	249,811	249,891	224,977	233,110
Other revenues	**3,374**	1,783	4,564	1,300	964
Total	**$295,718**	$251,594	$254,455	$226,277	$234,074
Kilowatt-Hour Sales (in thousands):					
Residential	**1,671,089**	1,579,068	1,539,792	1,428,337	1,456,651
Commercial	**1,369,448**	1,287,832	1,236,337	1,156,078	1,141,218
Industrial	**800,150**	713,448	900,012	881,261	838,753
Other	**135,824**	132,555	131,142	124,490	126,215
Total retail	**3,976,511**	3,712,903	3,807,283	3,590,166	3,562,837
Sales for resale - non-affiliates	**77,481**	51,548	53,294	94,280	91,610
Sales for resale - affiliates	**88,646**	76,988	58,415	54,509	41,808
Total	**4,142,638**	3,841,439	3,918,992	3,738,955	3,696,255
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.75**	7.12	7.10	6.76	6.98
Commercial	**7.46**	6.87	6.97	6.83	7.05
Industrial	**5.10**	4.52	4.21	4.01	4.42
Total retail	**7.11**	6.52	6.36	6.11	6.40
Sales for resale	**5.85**	5.87	6.77	3.71	3.84
Total sales	**7.06**	6.50	6.38	6.02	6.31
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,593**	14,100	14,061	13,231	13,771
Residential Average Annual Revenue Per Customer	**$1,131.08**	$1,003.39	$998.94	$894.73	$960.58
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**788**	788	788	788	788
Maximum Peak-Hour Demand (megawatts):					
Winter	**724**	719	582	625	666
Summer	**878**	875	846	802	811
Annual Load Factor (percent)	**53.4**	51.2	54.9	54.3	53.1
Plant Availability Fossil-Steam (percent):	**78.5**	72.8	72.9	93.7	77.6
Source of Energy Supply (percent):					
Coal	**51.6**	44.6	41.6	34.4	27.7
Oil and gas	**6.9**	12.3	12.9	5.2	3.1
Purchased power -					
From non-affiliates	**7.7**	5.3	3.4	1.4	2.1
From affiliates	**33.8**	37.8	42.1	59.0	67.1
Total	**100.0**	100.0	100.0	100.0	100.0

Items 10, 11, 12 and 13 for SOUTHERN are incorporated by reference to ELECTION OF DIRECTORS in SOUTHERN's definitive Proxy Statement relating to the 2001 Annual Meeting of Stockholders.

Additionally, Items 10, 11, 12 and 13 for ALABAMA, GEORGIA, GULF and MISSISSIPPI are incorporated by reference to the Information Statements of ALABAMA, GEORGIA, GULF and MISSISSIPPI relating to each of their respective 2001 Annual Meetings of Shareholders.

The ages of directors and executive officers in Item 10 set forth below are as of December 31, 2000.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Identification of directors of SAVANNAH.

G. Edison Holland, Jr.
President and Chief Executive Officer
Age 48
Served as Director since 7-15-97

Gus H. Bell (1)
Age 63
Served as Director since 7-20-99

Archie H. Davis (1)
Age 59
Served as Director since 2-18-97

Walter D. Gnann (1)
Age 65
Served as Director since 5-17-83

Robert B. Miller, III (1)
Age 55
Served as Director since 5-17-83

Arnold M. Tenenbaum (1)
Age 64
Served as Director since 5-17-77

(1) *No position other than Director.*

Each of the above is currently a director of SAVANNAH, serving a term running from the last annual meeting of SAVANNAH's stockholder (May 17, 2000) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director or nominee, other than any arrangements or understandings with directors or officers of SAVANNAH acting solely in their capacities as such.

Identification of executive officers of SAVANNAH.

G. Edison Holland, Jr.
President, Chief Executive Officer and Director
Age 48
Served as Executive Officer since 7-15-97

Anthony R. James
Vice President – Power Generation
Age 50
Served as Executive Officer since 7-27-00

W. Miles Greer
Vice President – Customer Operations and External Affairs
Age 57
Served as Executive Officer since 11-20-85

Kirby R. Willis
Vice President, Treasurer, Chief Financial Officer and Assistant Corporate Secretary
Age 49
Served as Executive Officer since 1-1-94

Each of the above is currently an executive officer of SAVANNAH, serving a term running from the meeting of the directors held on July 27, 2000 for the ensuing year.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he was or is to be selected as an officer, other than any arrangements or understandings with officers of SAVANNAH acting solely in their capacities as such.

Identification of certain significant employees.
None.

Family relationships.

None.

Business experience.

G. Edison Holland, Jr. - President and Chief Executive Officer since 1997. He previously served as Vice President of Power Generation/Transmission and Corporate Counsel of GULF from 1995 to 1997. Served as a partner in the law firm of Beggs & Lane from 1979 to 1997. Director of SunTrust Bank of Savannah.

Gus H. Bell, III – President and Chief Executive Officer of Hussey, Gay, Bell and DeYoung, Inc., (specializing in environmental, industrial, structural, architectural and civil engineering), Savannah, Georgia. Director of SunTrust Bank of Savannah.

Archie H. Davis - President and Chief Executive Officer of The Savannah Bancorp and The Savannah Bank, N.A., Savannah, Georgia. Member of the Board of Directors of Thomaston Mills, Thomaston, Georgia.

Walter D. Gnann - President of Walt's TV, Appliance and Furniture Co., Inc., Springfield, Georgia.

Robert B. Miller, III - President of American Building Systems, Inc., Savannah, Georgia.

Arnold M. Tenenbaum - President and Director of Chatham Steel Corporation. Director of First Union Bank of Georgia, First Union Bank of Savannah and Cerulean Corporation.

W. Miles Greer - Vice President – Customer Operations and External Affairs since 1998. He previously served as Vice President of Marketing and Customer Service from 1994 to 1998. Responsible for customer services, transmission and distribution, engineering, system operation and external affairs.

Anthony R. James – Vice President – Power Generation and Senior Production Officer since 2000. He also serves as Central Cluster Manager at GEORGIA's Plant Scherer. Responsible for operations and maintenance of Plants Kraft, Riverside and McIntosh.

Kirby R. Willis – Vice President, Treasurer and Chief Financial Officer since 1994 and Assistant Corporate Secretary effective 1998. Responsible primarily for accounting, financial, labor relations, corporate services, corporate compliance, environmental and safety activities.

Involvement in certain legal proceedings.

None

Section 16(a) Beneficial Ownership Reporting Compliance.

No late filers.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Table. The following table sets forth information concerning any Chief Executive Officer and the four most highly compensated executive officers of SAVANNAH serving during 2000.

		ANNUAL COMPENSATION			LONG-TERM COMPENSATION		
Name and Principal Position	**Year**	**Salary($)**	**Bonus($)**	**Other Annual Compensation ($)[1]**	**Number of Securities Underlying Stock Options (Shares)**	**Long-Term Incentive Payouts ($)[2]**	**All Other Compensation ($)[3]**
G. Edison Holland, Jr.							
President,	2000	295,812	243,263	24,438	25,667	-	15,453
Chief Executive	1999	254,914	42,626	21,588	8,375	166,052	13,392
Officer, Director	1998	233,330	26,019	17,309	7,951	128,608	8,246
Anthony R. James[4]	2000	175,048	161,442	-	12,752	-	7,582
Vice President,	1999	-	-	-	-	-	-
	1998	-	-	-	-	-	-
W. Miles Greer	2000	177,013	100,923	601	13,416	-	16,982
Vice President	1999	168,713	21,322	1,874	6,130	79,476	15,150
	1998	160,207	16,054	13	4,901	69,000	13,179
Kirby R. Willis							
Vice President,	2000	162,279	97,394	4,908	8,785	-	12,159
Chief Financial	1999	156,068	19,546	259	5,028	79,476	11,767
Officer, Treasurer	1998	155,236	15,554	13	4,748	69,000	10,581
Lewis A. Jeffers[5]	2000	142,850	96,835	2,856	7,543	-	7,245
Vice President	1999	134,538	19,023	379	3,809	63,146	6,972
	1998	-	-	-	-	-	-

1 Tax reimbursement by SAVANNAH on certain personal benefits, including membership fees of $11,669 for Mr. Holland, Jr. in 1998.

2 Payouts made in 1999 and 2000 for the four-year performance periods ending December 31, 1998 and 1999, respectively.

3 SAVANNAH contributions to the Employee Savings Plan (ESP), Employee Stock Ownership Plan (ESOP), Supplemental Benefit Plan (SBP) or Above-market earnings on deferred compensation (AME) and tax sharing benefits paid to participants who elected receipt of dividends on SOUTHERN's common stock held in the ESP are as follows:

Name	ESP	ESOP	SBP or AME	ESP Tax Benefit Sharing
G. Edison Holland, Jr.	$6,853	$810	$7,790	$489
Anthony R. James	6,772	810	-	-
W. Miles Greer	7,525	810	8,647	-
Kirby R. Willis	5,954	810	5,395	-
Lewis A. Jeffers	6,435	810	-	-

4 Mr. James was named an executive officer effective July 27, 2000.

5 Mr. Jeffers was named an executive officer of SAVANNAH effective November 2, 1999 and transferred to ALABAMA effective June 24, 2000.

STOCK OPTION GRANTS IN 2000

Stock Option Grants. The following table sets forth all stock option grants to the named executive officers of SAVANNAH during the year ending December 31, 2000.

	Individual Grants				Grant Date Value
Name	**# of Securities Underlying Options Granted[6]**	**% of Total Options Granted to Employees in Fiscal Year[7]**	**Exercise or Base Price (\$/Sh)[6]**	**Expiration Date[6]**	**Grant Date Present Value(\$)[8]**
SAVANNAH					
G. Edison Holland, Jr.	25,667	0.4	23.25	02/18/2010	147,842
Anthony R. James	12,752	0.2	23.25	02/18/2010	73,452
W. Miles Greer	13,416	0.2	23.25	02/18/2010	77,276
Kirby R. Willis	8,785	0.1	23.25	02/18/2010	50,602
Lewis A. Jeffers	7,543	0.1	23.25	02/18/2010	43,448

6 Performance Stock Plan grants were made on February 18, 2000, and vest annually at a rate of one-third on the anniversary date of the grant. Grants fully vest upon termination as a result of death, total disability, or retirement and expire five years after retirement, three years after death or total disability, or their normal expiration date if earlier. The exercise price is the average of the high and low fair market value of SOUTHERN's common stock on the date granted. Options may be transferred to family members, family trusts, and family limited partnerships.

7 A total of 6,977,038 stock options were granted in 2000.

8 Value was calculated using the Black-Scholes option valuation model. The actual value, if any, ultimately realized depends on the market value of SOUTHERN's common stock at a future date. Significant assumptions are shown below:

	Volatility	Risk-free rate of return	Dividend opportunity	Term	Discount for forfeiture risk: before vesting	Discount for forfeiture risk: after vesting
Black-Scholes Assumptions	22.14%	6.52%	50%	10 years	7.79%	12.40%

These assumptions reflect the effects of cash dividend equivalents paid to participants under the Performance Dividend Plan assuming targets are met.

AGGREGATED STOCK OPTION EXERCISES IN 2000 AND YEAR-END OPTION VALUES

Aggregated Stock Option Exercises. The following table sets forth information concerning options exercised during the year ending December 31, 2000 by the named executive officers and the value of unexercised options held by them as of December 31, 2000.

Name	Shares Acquired on Exercise (#)	Value Realized($)[10]	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#) Exercisable/ Unexercisable	Value of Unexercised In-the-Money Options at Fiscal Year-End($)[9] Exercisable/ Unexercisable
SAVANNAH				
G. Edison Holland, Jr.	18,323	220,862	32,261/33,900	325,274/310,486
Anthony R. James	-	-	8,456/17,259	77,991/157,055
W. Miles Greer	8,654	76,354	10,235/19,136	93,074/171,646
Kirby R. Willis	4,038	37,604	13,574/13,720	128,819/120,111
Lewis A. Jeffers	-	-	1,270/10,082	8,493/92,410

9 This column represents the excess of the fair market value of SOUTHERN's common stock of $33.25 per share, as of December 31, 2000, above the exercise price of the options. The Exercisable column reports the "value" of options that are vested and therefore could be exercised. The Unexercisable column reports the "value" of options that are not vested and therefore could not be exercised as of December 31, 2000.

10 The "Value Realized" is ordinary income, before taxes, and represents the amount equal to the excess of the fair market value of the shares at the time of exercise above the exercise price.

DEFINED BENEFIT OR ACTUARIAL PLAN DISCLOSURE

Pension Plan Table. The following table sets forth the estimated annual pension benefits payable at normal retirement age under SOUTHERN's qualified Pension Plan, as well as non-qualified supplemental benefits, based on the stated compensation and years of service with the SOUTHERN system for Messrs. Holland, James and Jeffers. Compensation for pension purposes is limited to the average of the highest three of the final 10 years' compensation — base salary plus the excess of annual and long-term incentive compensation over 25 percent of base salary (reported under column titled "Salary", "Bonus", and "Long-Term Incentive Payouts" in the Summary Compensation Table on page III-3).

The amounts shown in the table were calculated according to the final average pay formula and are based on a single life annuity without reduction for joint and survivor annuities (although married employees are required to have their pension benefits paid in one of various joint and survivor annuity forms, unless the employee elects otherwise with the spouse's consent) or computation of the Social Security offset which would apply in most cases. This offset amounts to one-half of the estimated Social Security benefit (primary insurance amount) in excess of $3,900 per year times the number of years of accredited service, divided by the total possible years of accredited service to normal retirement age.

	Years of Accredited Service					
Remuneration	**15**	**20**	**25**	**30**	**35**	**40**
$ 100,000	$ 25,500	$ 34,000	$ 42,500	$ 51,000	$ 59,500	$ 68,000
300,000	76,500	102,000	127,500	153,000	178,500	204,000
500,000	127,500	170,000	212,500	255,000	297,500	340,000
700,000	178,500	238,000	297,500	357,000	416,500	476,000
900,000	229,500	306,000	382,500	459,000	535,500	612,000
1,100,000	280,500	374,000	467,500	561,000	654,500	748,000
1,300,000	331,500	442,000	552,500	663,000	773,500	884,000

As of December 31, 2000, the applicable compensation levels and years of accredited service for SAVANNAH's named executives are presented in the following table:

Name	**Compensation Level**	**Accredited Years of Service**
G. Edison Holland, Jr.[11]	$431,348	17
Anthony R. James	246,604	21
W. Miles Greer[12]	237,392	16
Kirby R. Willis	225,952	26
Lewis A. Jeffers	197,400	21

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11 The number of accredited years of service includes 9 years and 3 months credited to Mr. Holland pursuant to a supplemental pension agreement.

12 The number of accredited years of service includes 7 years and 6 months credited to Mr. Greer pursuant to a supplemental pension agreement.

Effective January 1, 1998, SAVANNAH merged its pension plan into the SOUTHERN Pension Plan. SAVANNAH also has in effect a supplemental executive retirement plan for certain of its executive employees. The plan is designed to provide participants with a supplemental retirement benefit, which, in conjunction with social security and benefits under SOUTHERN's qualified pension plan, will equal 70 percent of the highest three of the final 10 years' average annual earnings (excluding incentive compensation).

The following table sets forth the estimated combined annual pension benefits under SOUTHERN's pension and SAVANNAH's supplemental executive retirement plans in effect during 2000 which are payable to Messrs Greer and Willis, upon retirement at the normal retirement age after designated periods of accredited service and at a specified compensation level.

	Years of Accredited Service		
Remuneration	**15**	**25**	**35**
$150,000	105,000	105,000	105,000
180,000	126,000	126,000	126,000
210,000	147,000	147,000	147,000
260,000	182,000	182,000	182,000
280,000	196,000	196,000	196,000
300,000	210,000	210,000	210,000
350,000	245,000	245,000	245,000
400,000	280,000	280,000	280,000
430,000	301,000	301,000	301,000
460,000	322,000	322,000	322,000

Compensation of Directors.

Standard Arrangements. The following table presents compensation paid to the directors during 2000 for service as a member of the board of directors and any board committee(s), except that employee directors received no fees or compensation for service as a member of the board of directors or any board committee. At the election of the director, all or a portion of the cash retainer may be payable in SOUTHERN's common stock, and all or a portion of the total fees may be deferred under the Deferred Compensation Plan until membership on the board is terminated.

Cash Retainer Fee	$10,000
Stock Retainer Fee	50 shares per quarter

Meeting Fees:
$750 for each Board or Committee meeting attended

Effective January 1, 1997, the Outside Directors Pension Plan (the "Plan") was terminated and benefits payable under the Plan were frozen. Non-employee directors serving as of January 1, 1997 were given a one-time election to receive a Plan benefit buy-out equal to the actuarial present value of future Plan benefits or receive benefits under the terms of the Plan at the annual retainer rate in effect on December 31, 1996. Directors who elected to receive the benefit buy-out were required to defer receipt of that amount under the Deferred Compensation Plan until termination from board membership. Directors who elected to continue to participate under the terms of the Plan are entitled to benefits upon retirement from the board on the retirement date designated in the respective companies' by-laws. The annual benefit payable is based upon length of service and varies from 75 percent of the annual retainer in effect on December 31, 1996 if the participant has at least 60 months of service on the board of one or more system companies, to 100 percent if the participant has at least 120 months of such service. Payments will continue for the greater of the lifetime of the participant or 10 years.

Other Arrangements. No director received other compensation for services as a director during the year ending December 31, 2000 in addition to or in lieu of that specified by the standard arrangements specified above.

Employment Contracts and Termination of Employment and Change in Control Arrangements.

SAVANNAH has adopted SOUTHERN's Change in Control Plan which is applicable to certain of its officers, and has entered into individual change in control agreements with its most highly compensated executive officers. If an executive is involuntarily terminated, other than for cause, within two years following a change in control of SOUTHERN the agreements provide for:

- lump sum payment of two or three times annual compensation,
- up to five years' coverage under group health and life insurance plans,
- immediate vesting of all stock options, stock appreciation rights, and restricted stock previously granted,
- payment of any accrued long-term and short-term bonuses and dividend equivalents, and
- payment of any excise tax liability incurred as a result of payments made under any individual agreements.

A SOUTHERN change in control is defined under the agreements as:

- acquisition of at least 20 percent of the SOUTHERN's stock,
- a change in the majority of the members of the SOUTHERN's board of directors,
- a merger or other business combination that results in SOUTHERN's shareholders immediately before the merger owning less than 65 percent of the voting power after the merger, or
- a sale of substantially all the assets of SOUTHERN.

A change in control of SAVANNAH is defined under the agreements as:

- acquisition of at least 50 percent of SAVANNAH's stock,
- a merger or other business combination unless SOUTHERN controls the surviving entity or
- a sale of substantially all the assets of SAVANNAH.

If a change in control affects only a subsidiary of SOUTHERN, these payments would only be made to executives of the affected subsidiary who are involuntarily terminated as a result of that change in control.

SOUTHERN also has amended its short- and long-term incentive plans to provide for pro-rata payments at not less than target-level performance if a change in control occurs and the plans are not continued or replaced with comparable plans.

Report on Repricing of Options.

None.

Compensation Committee Interlocks and Insider Participation.

None.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Security Ownership of Certain Beneficial Owners. SOUTHERN is the beneficial owner of 100% of the outstanding common stock of SAVANNAH.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 270 Peachtree Street, N.W. Atlanta, Georgia 30303		100%
	Registrant: SAVANNAH	10,844,635	

Security Ownership of Management. The following table shows the number of shares of SOUTHERN common stock owned by the SAVANNAH's directors, nominees and executive officers as of December 31, 2000. It is based on information furnished by the directors, nominees and executive officers. The shares owned by all directors, nominees and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2000.

Name of Directors, Nominees and Executive Officers	Title of Class	Number of Shares Beneficially Owned (1) (2)
Gus H. Bell, III	SOUTHERN Common	246
Archie H. Davis	SOUTHERN Common	495
Walter D. Gnann	SOUTHERN Common	2,689
G. Edison Holland, Jr.	SOUTHERN Common	43,848
Robert B. Miller, III	SOUTHERN Common	1,770
Arnold M. Tenenbaum	SOUTHERN Common	1,124
Anthony R. James	SOUTHERN Common	25,065
W. Miles Greer	SOUTHERN Common	18,605
Kirby R. Willis	SOUTHERN Common	23,240
The directors, nominees and executive officers as a group	SOUTHERN Common	117,083

(1) As used in this table, "beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security (i.e., the power to dispose of, or to direct the disposition of, a security).

(2) The shares shown include shares of SOUTHERN common stock of which certain directors and executive officers have the right to acquire beneficial ownership within 60 days pursuant to the Executive Stock Plan and/or Performance Stock Plan, as follows: Mr. Greer, 14,707 shares; Mr. Holland, 40,817 shares; Mr. James 12,707 shares, and Mr. Willis, 16,503 shares.

Changes in control. SOUTHERN and SAVANNAH know of no arrangements which may at a subsequent date result in any change in control.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Transactions with management and others.

Mr. Archie Davis is President of The Savannah Bank, N.A., Savannah, Georgia. During 2000, this bank furnished a number of regular banking services in the ordinary course of business to SAVANNAH. SAVANNAH intends to maintain normal banking relations with the aforesaid bank in the future.

Certain business relationships.

None.

Indebtedness of management.

None.

Transactions with promoters.

None.

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as a part of this report on this Form 10-K:

(1) Financial Statements:

Reports of Independent Public Accountants on the financial statements for SOUTHERN and Subsidiary Companies, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH are listed under Item 8 herein.

The financial statements filed as a part of this report for SOUTHERN and Subsidiary Companies, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH are listed under Item 8 herein.

(2) Financial Statement Schedules:

Reports of Independent Public Accountants as to Schedules for SOUTHERN and Subsidiary Companies, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH are included herein on pages IV-12 through IV-17.

Financial Statement Schedules for SOUTHERN and Subsidiary Companies, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH are listed in the Index to the Financial Statement Schedules at page S-1.

(3) Exhibits:

Exhibits for SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH are listed in the Exhibit Index at page E-1.

(b) Reports on Form 8-K during the fourth quarter of 2000 were as follows:

SOUTHERN filed Current Reports on Form 8-K:

Date of event:	November 27, 2000
Items reported:	Items 5 and 7
Date of event:	December 6, 2000
Items reported:	Items 5 and 7

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: H. Allen Franklin, President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

H. Allen Franklin
President and
Chief Executive Officer
(Principal Executive Officer)

Gale E. Klappa
Financial Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

W. Dean Hudson
Vice President, Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Daniel P. Amos	*L. G. Hardman III*
Dorrit J. Bern	*Donald M. James*
Thomas F. Chapman	*Zack T. Pate*
H. Allen Franklin	*Gerald J. St. Pe'*

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Elmer B. Harris, President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Elmer B. Harris
President, Chief Executive Officer and Director
(Principal Executive Officer)

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

Art P. Beattie
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong	*John T. Porter*
H. Allen Franklin	*Robert D. Powers*
R. Kent Henslee	*Andreas Renschler*
Carl E. Jones, Jr.	*C. Dowd Ritter*
James K. Lowder	*James H. Sanford*
Wallace D. Malone, Jr.	*John Cox Webb, IV*
Thomas C. Meredith	*James W. Wright*
William V. Muse	

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: David M. Ratcliffe, President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

David M. Ratcliffe
President, Chief Executive Officer and Director
(Principal Executive Officer)

Thomas A. Fanning
Executive Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Cliff S. Thrasher
Vice President, Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Daniel P. Amos	*James R. Lientz, Jr.*
Juanita P. Baranco	*G. Joseph Prendergast*
William A. Fickling, Jr.	*William Jerry Vereen*
H. Allen Franklin	*Carl Ware*
L. G. Hardman III	*E. Jenner Wood, III*

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: Travis J. Bowden, President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Travis J. Bowden
President, Chief Executive Officer and Director
(Principal Executive Officer)

Ronnie R. Labrato
Comptroller and Chief Financial Officer
(Principal Financial and Accounting Officer)

Directors:

Fred C. Donovan, Sr.	*W. Deck Hull, Jr.*
H. Allen Franklin	*Barbara H. Thames*

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Dwight H. Evans, President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Dwight H. Evans
President, Chief Executive Officer and Director
(Principal Executive Officer)

Michael W. Southern
Vice President, Secretary, Treasurer and
Chief Financial Officer
(Principal Financial and Accounting Officer)

Directors:

Robert S. Gaddis	*George A. Schloegel*
Linda T. Howard	*Philip J. Terrell*
Aubrey K. Lucas	*Gene Warr*
Malcolm Portera	

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SAVANNAH ELECTRIC AND POWER COMPANY

By: G. Edison Holland, Jr., President and Chief Executive Officer

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

G. Edison Holland, Jr.
President, Chief Executive Officer and Director
(Principal Executive Officer)

Kirby R. Willis
Vice President, Treasurer and
Chief Financial Officer
(Principal Financial and Accounting Officer)

Directors:

Gus H. Bell, III	*Robert B. Miller, III*
Archie H. Davis	*Arnold M. Tenenbaum*
Walter D. Gnann	

By: Wayne Boston (Wayne Boston, Attorney-in-fact)

Date: March 28, 2001

Exhibit 21. Subsidiaries of the Registrants.*

Name of Company	Jurisdiction of Organization
The Southern Company	Delaware
Southern Company Capital Trust I	Delaware
Southern Company Capital Trust II	Delaware
Southern Company Capital Trust III	Delaware
Southern Company Capital Trust IV	Delaware
Southern Company Capital Trust V	Delaware
Southern Company Capital Trust VI	Delaware
Southern Company Capital Trust VII	Delaware
Southern Company Capital Trust VIII	Delaware
Southern Company Capital Trust IX	Delaware
Alabama Power Company	Alabama
Alabama Power Capital Trust I	Delaware
Alabama Power Capital Trust II	Delaware
Alabama Power Capital Trust III	Delaware
Alabama Power Capital Trust IV	Delaware
Alabama Power Capital Trust V	Delaware
Alabama Property Company	Alabama
Southern Electric Generating Company	Alabama
Georgia Power Company	Georgia
Georgia Power Capital Trust I	Delaware
Georgia Power Capital Trust II	Delaware
Georgia Power Capital Trust III	Delaware
Georgia Power Capital Trust IV	Delaware
Georgia Power Capital Trust V	Delaware
Georgia Power Capital Trust VI	Delaware
Georgia Power L.P. Holdings Corp.	Georgia
Georgia Power Capital, L.P.	Delaware
Piedmont-Forrest Corporation	Georgia
Southern Electric Generating Company	Alabama
Gulf Power Company	Maine
Gulf Power Capital Trust I	Delaware
Gulf Power Capital Trust II	Delaware
Gulf Power Capital Trust III	Delaware
Mississippi Power Company	Mississippi
Mississippi Power Capital Trust I	Delaware
Mississippi Power Capital Trust II	Delaware
Mississippi Power Capital Trust III	Delaware
Savannah Electric and Power Company	Georgia
Savannah Electric Capital Trust I	Delaware

*This information is as of December 31, 2000. In addition, the list omits certain subsidiaries pursuant to paragraph (b)(21)(ii) of Regulation S-K Item 601.

ARTHUR ANDERSEN

Exhibit 23(a)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of The Southern Company and its subsidiaries and the related financial statement schedule, included in this Form 10-K, into The Southern Company's previously filed Registration Statement File Nos. 2-78617, 33-3546, 33-30171, 33-54415, 33-57951, 33-58371, 33-60427, 333-09077, 333-44127, 333-44261, 333-64871 and 333-31808.

Arthur Andersen LLP

Atlanta, Georgia
March 22, 2001

ARTHUR ANDERSEN

Exhibit 23(b)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of Alabama Power Company and the related financial statement schedule, included in this Form 10-K, into Alabama Power Company's previously filed Registration Statement File No. 333-67453.

Arthur Andersen LLP

Birmingham, Alabama
March 22, 2001

ARTHUR ANDERSEN

Exhibit 23(c)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of Georgia Power Company and the related financial statement schedule, included in this Form 10-K, into Georgia Power Company's previously filed Registration Statement File No. 333-75193.

Arthur Andersen LLP

Atlanta, Georgia
March 22, 2001

ARTHUR ANDERSEN

Exhibit 23(d)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of Gulf Power Company and the related financial statement schedule, included in this Form 10-K, into Gulf Power Company's previously filed Registration Statement File Nos. 33-50165 and 333-42033.

Arthur Andersen LLP

Atlanta, Georgia
March 22, 2001

ARTHUR ANDERSEN

Exhibit 23(e)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of Mississippi Power Company and the related financial statement schedule, included in this Form 10-K, into Mississippi Power Company's previously filed Registration Statement File No. 333-45069.

Arthur Andersen LLP

Atlanta, Georgia
March 22, 2001

ARTHUR ANDERSEN

Exhibit 23(f)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated February 28, 2001 on the financial statements of Savannah Electric and Power Company and the related financial statement schedule, included in this Form 10-K, into Savannah Electric and Power Company's previously filed Registration Statement File No. 333-46171.

Arthur Andersen LLP

Atlanta, Georgia
March 22, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To The Southern Company:

We have audited in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of The Southern Company and its subsidiaries included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to The Southern Company and its subsidiaries (page S-2) is the responsibility of The Southern Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic consolidated financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To Alabama Power Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Alabama Power Company included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to Alabama Power Company (page S-3) is the responsibility of Alabama Power Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Birmingham, Alabama
February 28, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To Georgia Power Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Georgia Power Company included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to Georgia Power Company (page S-4) is the responsibility of Georgia Power Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To Gulf Power Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Gulf Power Company included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to Gulf Power Company (page S-5) is the responsibility of Gulf Power Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To Mississippi Power Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Mississippi Power Company included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to Mississippi Power Company (page S-6) is the responsibility of Mississippi Power Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

ARTHUR ANDERSEN

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS AS TO SCHEDULE

To Savannah Electric and Power Company:

We have audited in accordance with auditing standards generally accepted in the United States, the financial statements of Savannah Electric and Power Company included in this Form 10-K, and have issued our report thereon dated February 28, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed under Item 14(a)(2) herein as it relates to Savannah Electric and Power Company (page S-7) is the responsibility of Savannah Electric and Power Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Arthur Andersen LLP

Atlanta, Georgia
February 28, 2001

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INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedule **Page**

Schedules I through V not listed above are omitted as not applicable or not required. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2000	$21,834	$31,329	$39	$31,403 (Note)	$21,799
1999	11,268	35,476	-	24,910 (Note)	21,834
1998	9,613	31,707	-	30,052 (Note)	11,268

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

ALABAMA POWER COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2000	$4,117	$9,093	$-	$ 6,973 (Note)	$6,237
1999	1,855	13,995	-	11,733 (Note)	4,117
1998	2,272	7,702	-	8,119 (Note)	1,855

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2000	$7,000	$10,794	$-	$12,694 (Note)	$5,100
1999	5,500	14,406	-	12,906 (Note)	7,000
1998	3,000	17,856	-	15,356 (Note)	5,500

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2000	$1,026	$2,702	$-	$2,426 (Note)	$1,302
1999	996	2,230	-	2,200(Note)	1,026
1998	796	2,288	-	2,088 (Note)	996

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998

(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2000	$697	$1,156	$14	$1,296 (Note)	$571
1999	621	1,964	-	1,888 (Note)	697
1998	698	1,510	31	1,618 (Note)	621

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

SAVANNAH ELECTRIC AND POWER COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2000..	$237	$999	$-	$829 (Note)	$407
1999..	284	594	-	641 (Note)	237
1998..	354	417	-	487 (Note)	284

Note: *Represents write-off of accounts receivable considered to be uncollectible, less recoveries of amounts previously written off.*

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EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the SEC, respectively, as the exhibits and in the file numbers indicated and are incorporated herein by reference. The exhibits marked with a pound sign are management contracts or compensatory plans or arrangements required to be filed herewith and required to be identified as such by Item 14 of Form 10-K. Reference is made to a duplicate list of exhibits being filed as a part of this Form 10-K, which list, prepared in accordance with Item 601 of Regulation S-K of the SEC, immediately precedes the exhibits being physically filed with this Form 10-K.

(1) Underwriting Agreements

GEORGIA

(c) - Distribution Agreement dated November 29, 1995 between GEORGIA and Lehman Brothers Inc.; Donaldson, Lufkin & Jenrette Securities Corporation; J. P. Morgan Securities Inc.; Salomon Brothers Inc and Smith Barney Inc. relating to $300,000,000 First Mortgage Bonds Secured Medium-Term Notes. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1995, as Exhibit 1(c).)

(3) Articles of Incorporation and By-Laws

SOUTHERN

(a) 1 - Composite Certificate of Incorporation of SOUTHERN, reflecting all amendments thereto through January 5, 1994. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A and in Certificate of Notification, File No. 70-8181, as Exhibit A.)

(a) 2 - By-laws of SOUTHERN as amended effective October 21, 1991, and as presently in effect. (Designated in Form U-1, File No. 70-8181, as Exhibit A-2.)

ALABAMA

(b) 1 - Charter of ALABAMA and amendments thereto through August 10, 1998. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in ALABAMA's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2 and Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4.)

* (b) 2 - Amendment to Charter of ALABAMA dated January 10, 2001.

(b) 3 - By-laws of ALABAMA as amended effective July 23, 1993, and as presently in effect. (Designated in Form U-1, File No. 70-8191, as Exhibit A-2.)

GEORGIA

(c) 1 - Charter of GEORGIA and amendments thereto through January 26, 1998. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in GEORGIA's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b) and in GEORGIA's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2.)

* (c) 2 - Amendment to Charter of GEORGIA dated February 16, 2001.

* (c) 3 - By-laws of GEORGIA as amended effective November 15, 2000, and as presently in effect.

GULF

(d) 1 - Restated Articles of Incorporation of GULF and amendments thereto through January 28, 1998. (Designated in Registration No. 33-43739 as Exhibit 4(b)-1, in Form 8-K dated January 15, 1992, File No. 0-2429, as Exhibit 1(b), in Form 8-K dated August 18, 1992, File No. 0-2429, as Exhibit 4(b)-2, in Form 8-K dated September 22, 1993, File No. 0-2429, as Exhibit 4, in Form 8-K dated November 3, 1993, File No. 0-2429, as Exhibit 4 and in GULF's Form 10-K for the year ended December 31, 1997, File No. 0-2429, as Exhibit 3(d)2.)

* (d) 2 - Amendment to Articles of Incorporation of GULF dated February 9, 2001.

* (d) 3 - By-laws of GULF as amended effective July 28, 2000, and as presently in effect.

MISSISSIPPI

(e) 1 - Articles of Incorporation of MISSISSIPPI, articles of merger of Mississippi Power Company (a Maine corporation) into MISSISSIPPI and articles of amendment to the articles of incorporation of MISSISSIPPI through December 31, 1997. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 0-6849, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 0-6849, as Exhibit 4(b)-3 and in MISSISSIPPI's Form 10-K for the year ended December 31, 1997, File No. 0-6849, as Exhibit 3(e)2.)

* (e) 2 - Amendment to Articles of Incorporation of MISSISSIPPI dated March 8, 2001.

(e) 3 - By-laws of MISSISSIPPI as amended effective April 2, 1996, and as presently in effect. (Designated in Form U5S for 1995, File No. 30-222-2, as Exhibit B-10.)

SAVANNAH

(f) 1 - Charter of SAVANNAH and amendments thereto through December 2, 1998. (Designated in Registration Nos. 33-25183 as Exhibit 4(b)-(1), 33-45757 as Exhibit 4(b)-(2), in Form 8-K dated November 9, 1993, File No. 1-5072, as Exhibit 4(b) and in SAVANNAH's Form 10-K for the year ended December 31, 1998, as Exhibit 3(f)2.)

* (f) 2 - By-laws of SAVANNAH as amended effective May 17, 2000, and as presently in effect.

(4) Instruments Describing Rights of Security Holders, Including Indentures

SOUTHERN

(a) 1 - Subordinated Note Indenture dated as of February 1, 1997, among SOUTHERN, Southern Company Capital Funding, Inc. and Bankers Trust Company, as Trustee, and indentures supplemental thereto dated as of February 4, 1997. (Designated in Registration Nos. 333-28349 as Exhibits 4.1 and 4.2 and 333-28355 as Exhibit 4.2.)

(a) 2 - Subordinated Note Indenture dated as of June 1, 1997, among SOUTHERN, Southern Company Capital Funding, Inc. and Bankers Trust Company, as Trustee, and indentures supplemental thereto through that dated as of December 23, 1998. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit (4)(a)2, in Form 8-K dated June 18, 1998, File No. 1-3526, as Exhibit 4.2 and in Form 8-K dated December 18, 1998, File No. 1-3526, as Exhibit 4.4.)

(a) 3 - Amended and Restated Trust Agreement of Southern Company Capital Trust I dated as of February 1, 1997. (Designated in Registration No. 333-28349 as Exhibit 4.6)

(a) 4 - Amended and Restated Trust Agreement of Southern Company Capital Trust II dated as of February 1, 1997. (Designated in Registration No. 333-28355 as Exhibit 4.6)

(a) 5 - Amended and Restated Trust Agreement of Southern Company Capital Trust III dated as of June 1, 1997. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit (4)(a)5.)

(a) 6 - Amended and Restated Trust Agreement of Southern Company Capital Trust IV dated as of June 1, 1998. (Designated in Form 8-K dated June 18, 1998, File No. 1-3526, as Exhibit 4.5.)

(a) 7 - Amended and Restated Trust Agreement of Southern Company Capital Trust V dated as of December 1, 1998. (Designated in Form 8-K dated December 18, 1998, File No. 1-3526, as Exhibit 4.7A.)

(a) 8 - Capital Securities Guarantee Agreement relating to Southern Company Capital Trust I dated as of February 1, 1997. (Designated in Registration No. 333-28349 as Exhibit 4.10)

(a) 9 - Capital Securities Guarantee Agreement relating to Southern Company Capital Trust II dated as of February 1, 1997. (Designated in Registration No. 333-28355 as Exhibit 4.10)

(a) 10 - Preferred Securities Guarantee Agreement relating to Southern Company Capital Trust III dated as of June 1, 1997. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit (4)(a)8.)

(a) 11 - Preferred Securities Guarantee Agreement relating to Southern Company Capital Trust IV dated as of June 1, 1998. (Designated in Form 8-K dated June 18, 1998, File No. 1-3626, as Exhibit 4.8.)

(a) 12 - Preferred Securities Guarantee Agreement relating to Southern Company Capital Trust V dated as of December 1, 1998. (Designated in Form 8-K dated December 18, 1998, File No. 1-3526, as Exhibit 4.11A.)

ALABAMA

(b) 1 - Indenture dated as of January 1, 1942, between ALABAMA and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, and indentures supplemental thereto through that dated as of December 1, 1994. (Designated in Registration Nos. 2-59843 as Exhibit 2(a)-2, 2-60484 as Exhibits 2(a)-3 and 2(a)-4, 2-60716 as Exhibit 2(c), 2-67574 as Exhibit 2(c), 2-68687 as Exhibit 2(c), 2-69599 as Exhibit 4(a)-2, 2-71364 as Exhibit 4(a)-2, 2-73727 as Exhibit 4(a)-2, 33-5079 as Exhibit 4(a)-2, 33-17083 as Exhibit 4(a)-2, 33-22090 as Exhibit 4(a)-2, in ALABAMA's Form 10-K for the year ended December 31, 1990, File No. 1-3164, as Exhibit 4(c), in Registration Nos. 33-43917 as Exhibit 4(a)-2, 33-45492 as Exhibit 4(a)-2, 33-48885 as Exhibit 4(a)-2, 33-48917 as Exhibit 4(a)-2, in Form 8-K dated January 20, 1993, File No. 1-3164, as Exhibit 4(a)-3, in Form 8-K dated February 17, 1993, File No. 1-3164, as Exhibit 4(a)-3, in Form 8-K dated March 10, 1993, File No. 1-3164, as Exhibit 4(a)-3, in Certificate of Notification, File No. 70-8069, as Exhibits A and B, in Form 8-K dated June 24, 1993, File No. 1-3164, as Exhibit 4, in Certificate of Notification, File No. 70-8069, as Exhibit A, in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(b), in Certificate of Notification, File No. 70-8069, as Exhibits A and B, in Certificate of Notification, File No. 70-8069, as Exhibit A, in Certificate of Notification, File No. 70-8069, as Exhibit A and in Form 8-K dated November 30, 1994, File No. 1-3164, as Exhibit 4.)

(b) 2 - Subordinated Note Indenture dated as of January 1, 1996, between ALABAMA and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, and indenture supplemental thereto dated as of January 1, 1996. (Designated in Certificate of Notification, File No. 70-8461, as Exhibits E and F.)

(b) 3 - Subordinated Note Indenture dated as of January 1, 1997, between ALABAMA and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through that dated as of February 25, 1999. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2 and in Form 8-K dated February 18, 1999, File No. 3164, as Exhibit 4.2.)

(b) 4 - Senior Note Indenture dated as of December 1, 1997, between ALABAMA and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through that dated May 18, 2000. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2 and in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2.)

(b) 5 - Amended and Restated Trust Agreement of Alabama Power Capital Trust I dated as of January 1, 1996. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit D.)

(b) 6 - Amended and Restated Trust Agreement of Alabama Power Capital Trust II dated as of January 1, 1997. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibit 4.5.)

(b) 7 - Amended and Restated Trust Agreement of Alabama Power Capital Trust III dated as of February 1, 1999. (Designated in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.5.)

(b) 8 - Guarantee Agreement relating to Alabama Power Capital Trust I dated as of January 1, 1996. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit G.)

(b) 9 - Guarantee Agreement relating to Alabama Power Capital Trust II dated as of January 1, 1997. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibit 4.8.)

(b) 10 - Guarantee Agreement relating to Alabama Power Capital Trust III dated as of February 1, 1999. (Designated in Form 8-K dated February 18, 1999, File No. 1-3164, as Exhibit 4.8.)

GEORGIA

(c) 1 - Indenture dated as of March 1, 1941, between GEORGIA and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, and indentures supplemental thereto dated as of March 1, 1941, March 3, 1941 (3 indentures), March 6, 1941 (139 indentures), March 1, 1946 (88 indentures) and December 1, 1947, through October 15, 1995. (Designated in Registration Nos. 2-4663 as Exhibits B-3 and B-3(a), 2-7299 as Exhibit 7(a)-2, 2-61116 as Exhibit 2(a)-3 and 2(a)-4, 2-62488 as Exhibit 2(a)-3, 2-63393 as Exhibit 2(a)-4, 2-63705 as Exhibit 2(a)-3, 2-68973 as Exhibit 2(a)-3, 2-70679 as Exhibit 4(a)-(2), 2-72324 as Exhibit 4(a)-2, 2-73987 as Exhibit 4(a)-(2), 2-77941 as Exhibits 4(a)-(2) and 4(a)-(3), 2-79336 as Exhibit 4(a)-(2), 2-81303 as Exhibit 4(a)-(2), 2-90105 as Exhibit 4(a)-(2), 33-5405 as Exhibit 4(a)-(2), 33-14367 as Exhibits 4(a)-(2) and 4(a)-(3), 33-22504 as Exhibits 4(a)-(2), 4(a)-(3) and 4(a)-(4), 33-32420 as Exhibit 4(a)-(2), 33-35683 as Exhibit 4(a)-(2), in GEORGIA's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 4(a)(3), in Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibit 4(a)(5), in Registration No. 33-48895 as Exhibit 4(a)-(2), in Form 8-K dated August 26, 1992, File No. 1-6468, as Exhibit 4(a)-(3), in Form 8-K dated September 9, 1992, File No. 1-6468, as Exhibits 4(a)-(3) and 4(a)-(4), in Form 8-K dated September 23, 1992, File No. 1-6468, as Exhibit 4(a)-(3), in Form 8-A dated October 12, 1992, as Exhibit 2(b), in Form 8-K dated January 27, 1993, File No. 1-6468, as Exhibit 4(a)-(3), in Registration No. 33-49661 as Exhibit 4(a)-(2), in Form 8-K dated July 26, 1993, File No. 1-6468, as Exhibit 4, in Certificate of Notification, File No. 70-7832, as Exhibit M, in Certificate of Notification, File No. 70-7832, as Exhibit C, in Certificate of Notification, File No. 70-7832, as Exhibits K and L, in Certificate of Notification, File No. 70-8443, as Exhibit C, in Certificate of Notification, File No. 70-8443, as Exhibit C, in Certificate of Notification, File No. 70-8443, as Exhibit E, in Certificate of Notification, File No. 70-8443, as Exhibit E, in Certificate of Notification, File No. 70-8443, as Exhibit E, in GEORGIA's Form 10-K for the year ended December 31, 1994, File No. 1-6468, as Exhibits 4(c)2 and 4(c)3, in Certificate of Notification, File No. 70-8443, as Exhibit C, in Certificate of Notification, File No. 70-8443, as Exhibit C, in Form 8-K dated May 17, 1995, File No. 1-6468, as Exhibit 4 and in GEORGIA's Form 10-K for the year ended December 31, 1995, File No. 1-6468, as Exhibits 4(c)2, 4(c)3, 4(c)4, 4(c)5 and 4(c)6.)

(c) 2 - Subordinated Note Indenture dated as of August 1, 1996, between GEORGIA and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through January 1, 1997. (Designated in Form 8-K dated August 21, 1996, File No. 1-6468, as Exhibits 4.1 and 4.2 and in Form 8-K dated January 9, 1997, File No. 1-6468, as Exhibit 4.2.)

(c) 3 - Subordinated Note Indenture dated as of June 1, 1997, between GEORGIA and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through that dated as of February 25, 1999. (Designated in Certificate of Notification, File No. 70-8461, as Exhibits D and E and Form 8-K dated February 17, 1999, File No. 1-6468, as Exhibit 4.4.)

(c) 4 - Senior Note Indenture dated as of January 1, 1998, between GEORGIA and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through that dated as of February 23, 2001. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b) and in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2.)

(c) 5 - Amended and Restated Trust Agreement of Georgia Power Capital Trust I dated as of August 1, 1996. (Designated in Form 8-K dated August 21, 1996, File No. 1-6468, as Exhibit 4.5.)

(c) 6 - Amended and Restated Trust Agreement of Georgia Power Capital Trust II dated as of January 1, 1997. (Designated in Form 8-K dated January 9, 1997, File No. 1-6468, as Exhibit 4.5.)

(c) 7 - Amended and Restated Trust Agreement of Georgia Power Capital Trust III dated as of June 1, 1997. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit C.)

(c) 8 - Amended and Restated Trust Agreement of Georgia Power Capital Trust IV dated as of February 1, 1999. (Designated in Form 8-K dated February 17, 1999, as Exhibit 4.7-A)

(c) 9 - Guarantee Agreement relating to Georgia Power Capital Trust I dated as of August 1, 1996. (Designated in Form 8-K dated August 21, 1996, File No. 1-6468, as Exhibit 4.8.)

(c) 10 - Guarantee Agreement relating to Georgia Power Capital Trust II dated as of January 1, 1997. (Designated in Form 8-K dated January 9, 1997, File No. 1-6468, as Exhibit 4.8.)

(c) 11 - Guarantee Agreement relating to Georgia Power Capital Trust III dated as of June 1, 1997. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit F.)

(c) 12 - Guarantee Agreement relating to Georgia Power Capital Trust IV dated as of February 1, 1999. (Designated in Form 8-K dated February 17, 1999, as Exhibit 4.11-A.)

GULF

(d) 1 - Indenture dated as of September 1, 1941, between GULF and The Chase Manhattan Bank (formerly The Chase Manhattan Bank (National Association)), as Trustee, and indentures supplemental thereto through November 1, 1996. (Designated in Registration Nos. 2-4833 as Exhibit B-3, 2-62319 as Exhibit 2(a)-3, 2-63765 as Exhibit 2(a)-3, 2-66260 as Exhibit 2(a)-3, 33-2809 as Exhibit 4(a)-2, 33-43739 as Exhibit 4(a)-2, in GULF's Form 10-K for the year ended December 31, 1991, File No. 0-2429, as Exhibit 4(b), in Form 8-K dated August 18, 1992, File No. 0-2429, as Exhibit 4(a)-3, in Registration No. 33-50165 as Exhibit 4(a)-2, in Form 8-K dated July 12, 1993, File No. 0-2429, as Exhibit 4, in Certificate of Notification, File No. 70-8229, as Exhibit A, in Certificate of Notification, File No. 70-8229, as Exhibits E and F, in Form 8-K dated January 17, 1996, File No. 0-2429, as Exhibit 4, in Certificate of Notification, File No. 70-8229, as Exhibit A, in Certificate of Notification, File No. 70-8229, as Exhibit A and in Form 8-K dated November 6, 1996, File No. 0-2429, as Exhibit 4.)

(d) 2 - Subordinated Note Indenture dated as of January 1, 1997, between GULF and The Chase Manhattan Bank, as Trustee, and indentures supplemental thereto through that dated as of January 1, 1998. (Designated in Form 8-K dated January 27, 1997, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated July 28, 1997, File No. 0-2429, as Exhibit 4.2 and in Form 8-K dated January 13, 1998, File No. 0-2429, as Exhibit 4.2.)

(d) 3 - Senior Note Indenture dated as of January 1, 1998, between GULF and The Chase Manhattan Bank, as Trustee, and indenture supplemental thereto dated as of August 24, 1999. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2 and in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2.)

(d) 4 - Amended and Restated Trust Agreement of Gulf Power Capital Trust I dated as of January 1, 1997. (Designated in Form 8-K dated January 27, 1997, File No. 0-2429, as Exhibit 4.5.)

(d) 5 - Amended and Restated Trust Agreement of Gulf Power Capital Trust II dated as of January 1, 1998. (Designated in Form 8-K dated January 13, 1998, File No. 0-2429, as Exhibit 4.5.)

(d) 6 - Guarantee Agreement relating to Gulf Power Capital Trust I dated as of January 1, 1997. (Designated in Form 8-K dated January 27, 1997, File No. 0-2429, as Exhibit 4.8.)

(d) 7 - Guarantee Agreement relating to Gulf Power Capital Trust II dated as of January 1, 1998. (Designated in Form 8-K dated January 13, 1998, File No. 0-2429, as Exhibit 4.8.)

MISSISSIPPI

(e) 1 - Indenture dated as of September 1, 1941, between MISSISSIPPI and Bankers Trust Company, as Successor Trustee, and indentures supplemental thereto through December 1, 1995. (Designated in Registration Nos. 2-4834 as Exhibit B-3, 2-62965 as Exhibit 2(b)-2, 2-66845 as Exhibit 2(b)-2, 2-71537 as Exhibit 4(a)-(2), 33-5414 as Exhibit 4(a)-(2), 33-39833 as Exhibit 4(a)-2, in MISSISSIPPI's Form 10-K for the year ended December 31, 1991, File No. 0-6849, as Exhibit 4(b), in Form 8-K dated August 5, 1992, File No. 0-6849, as Exhibit 4(a)-2, in Second Certificate of Notification, File No. 70-7941, as Exhibit I, in MISSISSIPPI's Form 8-K dated February 26, 1993, File No. 0-6849, as Exhibit 4(a)-2, in Certificate of Notification, File No. 70-8127, as Exhibit A, in Form 8-K dated June 22, 1993, File No. 0-6849, as Exhibit 1, in Certificate of Notification, File No. 70-8127, as Exhibit A, in Form 8-K dated March 8, 1994, File No. 0-6849, as Exhibit 4, in Certificate of Notification, File No. 70-8127, as Exhibit C and in Form 8-K dated December 5, 1995, File No. 0-6849, as Exhibit 4.)

(e) 2 - Senior Note Indenture dated as of May 1, 1998 between MISSISSIPPI and Bankers Trust Company, as Trustee and indentures supplemental thereto through March 28, 2000. (Designated in Form 8-K dated May 14, 1998, File No. 0-6849, as Exhibits 4.1, 4.2(a) and 4.2(b) and in Form 8-K dated March 22, 2000, File No. 0-6849, as Exhibit 4.2.)

(e) 3 - Subordinated Note Indenture dated as of February 1, 1997, between MISSISSIPPI and Bankers Trust Company, as Trustee, and indenture supplemental thereto dated as of February 1, 1997. (Designated in Form 8-K dated February 20, 1997, File No. 0-6849, as Exhibits 4.1 and 4.2.)

(e) 4 - Amended and Restated Trust Agreement of Mississippi Power Capital Trust I dated as of February 1, 1997. (Designated in Form 8-K dated February 20, 1997, File No. 0-6849, as Exhibit 4.5.)

(e) 5 - Guarantee Agreement relating to Mississippi Power Capital Trust I dated as of February 1, 1997. (Designated in Form 8-K dated February 20, 1997, File No. 0-6849, as Exhibit 4.8.)

SAVANNAH

(f) 1 - Indenture dated as of March 1, 1945, between SAVANNAH and The Bank of New York, New York, as Trustee, and indentures supplemental thereto through May 1, 1996. (Designated in Registration Nos. 33-25183 as Exhibit 4(a)-(1), 33-41496 as Exhibit 4(a)-(2), 33-45757 as Exhibit 4(a)-(2), in SAVANNAH's Form 10-K for the year ended December 31, 1991, File No. 1-5072, as Exhibit 4(b), in Form 8-K dated July 8, 1992, File No. 1-5072, as Exhibit 4(a)-3, in Registration No. 33-50587 as Exhibit 4(a)-(2), in Form 8-K dated July 22, 1993, File No. 1-5072, as Exhibit 4, in Form 8-K dated May 18, 1995, File No. 1-5072, as Exhibit 4 and in Form 8-K dated May 23, 1996, File No. 1-5072, as Exhibit 4.)

(f) 2 - Senior Note Indenture dated as of March 1, 1998 between SAVANNAH and The Bank of New York, as Trustee and indenture supplemental thereto dated as of March 1, 1998. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2.)

(f) 3 - Subordinated Note Indenture dated as of December 1, 1998, between SAVANNAH and The Bank of New York, as Trustee, and indenture supplemental thereto dated as of December 9, 1998. (Designated in Form 8-K dated December 3, 1998, File No. 1-5072, as Exhibit 4.3 and 4.4.)

(f) 4 - Amended and Restated Trust Agreement of Savannah Electric Capital Trust I dated as of December 1, 1998. (Designated in Form 8-K dated December 3, 1998, File No. 1-5072, as Exhibit 4.7.)

(f) 5 - Guarantee Agreement relating to Savannah Electric Capital Trust I dated as of December 1, 1998. (Designated in Form 8-K dated December 3, 1998, File No. 1-5072, as Exhibit 4.11.)

(10) Material Contracts

SOUTHERN

(a) 1 - Service contracts dated as of January 1, 1984, between SCS and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SEGCO and SOUTHERN and Amendment No. 1 dated as of September 6, 1985 between SCS and SOUTHERN. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1984, File No. 1-3526, as Exhibit 10(a) and in SOUTHERN's Form 10-K for the year ended December 31, 1985, File No. 1-3526, as Exhibit 10(a)(3).)

(a) 2 - Service contract dated as of July 17, 1981, between SCS and Mirant. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1985, File No. 1-3526, as Exhibit 10(a)(2).)

(a) 3 - Service contract dated as of March 3, 1988, between SCS and SAVANNAH. (Designated in SAVANNAH's Form 10-K for the year ended December 31, 1987, File No. 1-5072, as Exhibit 10-p.)

(a) 4 - Service contract dated as of January 15, 1991, between SCS and Southern Nuclear. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1991, File No. 1-3526, as Exhibit 10(a)(4).)

(a) 5 - Service contract dated as of December 12, 1994, between SCS and Mobile Energy Services Company, Inc. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1994, File No. 1-3526, as Exhibit 10(a)58.)

* (a) 6 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS.

(a) 7 - Agreement dated as of January 27, 1959, Amendment No. 1 dated as of October 27, 1982 and Amendment No. 2 dated November 4, 1993 and effective June 1, 1994, among SEGCO, ALABAMA and GEORGIA. (Designated in Registration No. 2-59634 as Exhibit 5(c), in GEORGIA's Form 10-K for the year ended December 31, 1982, File No. 1-6468, as Exhibit 10(d)(2) and in ALABAMA's Form 10-K for the year ended December 31, 1994, File No. 1-3164, as Exhibit 10(b)18.)

(a) 8 - Joint Committee Agreement dated as of August 27, 1976, among GEORGIA, OPC, MEAG and Dalton. (Designated in Registration No. 2-61116 as Exhibit 5(d).)

(a) 9 - Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement dated as of January 6, 1975, between GEORGIA and OPC. (Designated in Form 8-K for January, 1975, File No. 1-6468, as Exhibit (b)(1).)

(a) 10 - Edwin I. Hatch Nuclear Plant Operating Agreement dated as of January 6, 1975, between GEORGIA and OPC. (Designated in Form 8-K for January, 1975, File No. 1-6468, as Exhibit (b)(3).)

(a) 11 - Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between GEORGIA and OPC. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)

(a) 12 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of March 26, 1976, between GEORGIA and OPC. (Designated in Certificate of Notification, File No. 70-5592, as Exhibit A.)

(a) 13 - Plant Hal Wansley Operating Agreement dated as of March 26, 1976, between GEORGIA and OPC. (Designated in Certificate of Notification, File No. 70-5592, as Exhibit B.)

(a) 14 - Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement dated as of August 27, 1976, between GEORGIA, MEAG and Dalton. (Designated in Form 8-K dated as of June 13, 1977, File No. 1-6468, as Exhibit (b)(1).)

(a) 15 - Edwin I. Hatch Nuclear Plant Operating Agreement dated as of August 27, 1976, between GEORGIA, MEAG and Dalton. (Designated in Form 8-K for February 1977, File No. 1-6468, as Exhibit (b)(2).)

(a) 16 - Alvin W. Vogtle Nuclear Units Number One and Two Purchase and Ownership Participation Agreement dated as of August 27, 1976 and Amendment No. 1 dated as of January 18, 1977, among GEORGIA, OPC, MEAG and Dalton. (Designated in Form U-1, File No. 70-5792, as Exhibit B-1 and in Form 8-K for January 1977, File No. 1-6468, as Exhibit (B)(3).)

(a) 17 - Alvin W. Vogtle Nuclear Units Number One and Two Operating Agreement dated as of August 27, 1976, among GEORGIA, OPC, MEAG and Dalton. (Designated in Form U-1, File No. 70-5792, as Exhibit B-2.)

(a) 18 - Alvin W. Vogtle Nuclear Units Number One and Two Purchase, Amendment, Assignment and Assumption Agreement dated as of November 16, 1983, between GEORGIA and MEAG. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1983, File No. 1-6468, as Exhibit 10(k)(4).)

(a) 19 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of August 27, 1976, between GEORGIA and MEAG. (Designated in Form 8-K dated as of July 5, 1977, File No. 1-6468, as Exhibit (b)(2).)

(a) 20 - Plant Hal Wansley Operating Agreement dated as of August 27, 1976, between GEORGIA and MEAG. (Designated in Form 8-K dated as of July 5, 1977, File No. 1-6468, as Exhibit (b)(4).)

(a) 21 - Nuclear Operating Agreement between Southern Nuclear and GEORGIA dated as of July 1, 1993. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 10(a)21.)

(a) 22 - Pseudo Scheduling and Services Agreement between GEORGIA and MEAG dated as of April 8, 1997. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 10(a)22.)

(a) 23 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of April 19, 1977, between GEORGIA and Dalton. (Designated in Form 8-K dated as of June 13, 1977, File No. 1-6468, as Exhibit (b)(3).)

(a) 24 - Plant Hal Wansley Operating Agreement dated as of April 19, 1977, between GEORGIA and Dalton. (Designated in Form 8-K dated as of June 13, 1977, File No. 1-6468, as Exhibit (b)(7).)

(a) 25 - Plant Robert W. Scherer Units Number One and Two Purchase and Ownership Participation Agreement dated as of May 15, 1980, Amendment No. 1 dated as of December 30, 1985, Amendment No. 2 dated as of July 1, 1986, Amendment No. 3 dated as of August 1, 1988 and Amendment No. 4 dated as of December 31, 1990, among GEORGIA, OPC, MEAG and Dalton. (Designated in Form U-1, File No. 70-6481, as Exhibit B-3, in SOUTHERN's Form 10-K for the year ended December 31, 1987, File No. 1-3526, as Exhibit 10(o)(2), in SOUTHERN's Form 10-K for the year ended December 31, 1989, File No. 1-3526, as Exhibit 10(n)(2) and in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)54.)

(a) 26 - Plant Robert W. Scherer Units Number One and Two Operating Agreement dated as of May 15, 1980, Amendment No. 1 dated as of December 3, 1985 and Amendment No. 2 dated as of December 31, 1990, among GEORGIA, OPC, MEAG and Dalton. (Designated in Form U-1, File No. 70-6481, as Exhibit B-4, in SOUTHERN's Form 10-K for the year ended December 31, 1987, File No. 1-3526, as Exhibit 10(o)(4) and in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)55.)

(a) 27 - Plant Robert W. Scherer Purchase, Sale and Option Agreement dated as of May 15, 1980, between GEORGIA and MEAG. (Designated in Form U-1, File No. 70-6481, as Exhibit B-1.)

(a) 28 - Plant Robert W. Scherer Purchase and Sale Agreement dated as of May 16, 1980, between GEORGIA and Dalton. (Designated in Form U-1, File No. 70-6481, as Exhibit B-2.)

(a) 29 - Plant Robert W. Scherer Unit Number Three Purchase and Ownership Participation Agreement dated as of March 1, 1984, Amendment No. 1 dated as of July 1, 1986 and Amendment No. 2 dated as of August 1, 1988, between GEORGIA and GULF. (Designated in Form U-1, File No. 70-6573, as Exhibit B-4, in SOUTHERN's Form 10-K for the year ended December 31, 1987, as Exhibit 10(o)(2) and in SOUTHERN's Form 10-K for the year ended December 31, 1989, as Exhibit 10(n)(2).)

(a) 30 - Plant Robert W. Scherer Unit Number Three Operating Agreement dated as of March 1, 1984, between GEORGIA and GULF. (Designated in Form U-1, File No. 70-6573, as Exhibit B-5.)

(a) 31 - Plant Robert W. Scherer Unit No. Four Amended and Restated Purchase and Ownership Participation Agreement by and among GEORGIA, FP&L and JEA, dated as of December 31, 1990 and Amendment No. 1 dated as of June 15, 1994. (Designated in Form U-1, File No. 70-7843, as Exhibit B-1 and in SOUTHERN's Form 10-K for the year ended December 31, 1994, File No. 1-3526, as Exhibit 10(a)60.)

(a) 32 - Plant Robert W. Scherer Unit No. Four Operating Agreement by and among GEORGIA, FP&L and JEA, dated as of December 31, 1990 and Amendment No. 1 dated as of June 15, 1994. (Designated in Form U-1, File No. 70-7843, as Exhibit B-2 and in SOUTHERN's Form 10-K for the year ended December 31, 1994, File No. 1-3526, as Exhibit 10(a)61.)

(a) 33 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. (Designated in SAVANNAH's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(d).)

(a) 34 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. (Designated in SAVANNAH's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(e).)

(a) 35 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. (Designated in SAVANNAH's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(f).)

(a) 36 - Rocky Mountain Pumped Storage Hydroelectric Project Ownership Participation Agreement dated November 18, 1988, between OPC and GEORGIA. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1988, File No. 1-6468, as Exhibit 10(x).)

(a) 37 - Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement dated November 18, 1988, between OPC and GEORGIA. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1988, File No. 1-6468, as Exhibit 10(y).)

(a) 38 - Purchase and Ownership Agreement for Joint Ownership Interest in the James H. Miller, Jr. Steam Electric Generating Plant Units One and Two dated November 18, 1988, between ALABAMA and AEC. (Designated in Form U-1, File No. 70-7609, as Exhibit B-1.)

(a) 39 - Operating Agreement for Joint Ownership Interest in the James H. Miller, Jr. Steam Electric Generating Plant Units One and Two dated November 18, 1988, between ALABAMA and AEC. (Designated in Form U-1, File No. 70-7609, as Exhibit B-2.)

(a) 40 - Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Gulf States and MISSISSIPPI. (Designated in MISSISSIPPI's Form 10-K for the year ended December 31, 1981, File No. 0-6849, as Exhibit 10(f), in MISSISSIPPI's Form 10-K for the year ended December 31, 1982, File No. 0-6849, as Exhibit 10(f)(2) and in MISSISSIPPI's Form 10-K for the year ended December 31, 1983, File No. 0-6849, as Exhibit 10(f)(3).)

(a) 41 - Long Term Transaction Service Agreement between GEORGIA and OPC dated as of February 26, 1999. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)46.)

(a) 42 - Revised and Restated Coordination Services Agreement between and among GEORGIA, OPC and Georgia Systems Operations Corporation dated as of September 10, 1997. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 10(a)48.)

(a) 43 - Amended and Restated Nuclear Managing Board Agreement for Plant Hatch and Plant Vogtle among GEORGIA, OPC, MEAG and Dalton dated as of July 1, 1993. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)49.)

(a) 44 - Integrated Transmission System Agreement, Power Sale and Coordination Umbrella Agreement between GEORGIA and OPC dated as of November 12, 1990. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(ff).)

(a) 45 - Revised and Restated Integrated Transmission System Agreement between GEORGIA and Dalton dated as of December 7, 1990. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)

(a) 46 - Revised and Restated Integrated Transmission System Agreement between GEORGIA and MEAG dated as of December 7, 1990. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)

(a) 47 - Long Term Transmission Service Agreement between Entergy Power, Inc. and ALABAMA, MISSISSIPPI and SCS. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1992, File No. 1-3526, as Exhibit 10(a)53.)

(a) 48 - Plant Scherer Managing Board Agreement dated as of December 31, 1990 among GEORGIA, OPC, MEAG, Dalton, GULF, FP&L and JEA. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)56.)

(a) 49 - Plant McIntosh Combustion Turbine Purchase and Ownership Participation Agreement between GEORGIA and SAVANNAH dated as of December 15, 1992. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)57.)

(a) 50 - Plant McIntosh Combustion Turbine Operating Agreement between GEORGIA and SAVANNAH dated as of December 15, 1992. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1993, File No. 1-3526, as Exhibit 10(a)58.)

(a) 51 - Operating Agreement for the Joseph M. Farley Nuclear Plant between ALABAMA and Southern Nuclear dated as of December 23, 1991. (Designated in Form U-1, File No. 70-7530, as Exhibit B-7.)

* (a) 52 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2001.

(a) 53 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)61 and in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)61.)

* (a) 54 - Amendment Number Six to The Southern Company Employee Savings Plan.

(a) 55 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)62 and in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)63.)

* (a) 56 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan.

* (a) 57 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000.

* (a) 58 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000.

* (a) 59 - The Deferred Compensation Plan for the Directors of The Southern Company, Amended and Restated effective February 19, 2001.

(a) 60 - The Southern Company Outside Directors Pension Plan. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1994, File No. 1-3526, as Exhibit 10(a)77.)

* (a) 61 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001.

(a) 62 - The Southern Company Outside Directors Stock Plan and First Amendment thereto. (Designated in Registration No. 33-54415 as Exhibit 4(c) and in SOUTHERN's Form 10-K for the year ended December 31, 1995, File No. 1-3526, as Exhibit 10(a)79.)

* (a) 63 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000.

* (a) 64 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000.

(a) 65 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1996, File No. 1-3526, as Exhibit 10(a)83, in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 10(a)79, in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)71 and in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)72.)

* (a) 66 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan.

* (a) 67 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1, 2000.

* (a) 68 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000.

(a) 69 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 10(a)82, in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)76 and in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)76.)

* (a) 70 - Amendment Number Eight to The Southern Company Performance Sharing Plan.

* (a) 71 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000.

* (a) 72 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000.

* (a) 73 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000.

(a) 74 - Deferred Compensation Agreement between SOUTHERN, GEORGIA and Henry Allen Franklin and First Amendment and Assignment to SCS. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)80 and in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)84.)

(a) 75 - Deferred Compensation Agreement between SOUTHERN, Southern Nuclear and William G. Hairston III. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)81.)

(a) 76 - Deferred Compensation Agreement between SOUTHERN, GEORGIA and Warren Y. Jobe. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)82.)

(a) 77 - Deferred Compensation Agreement between SOUTHERN, Southern Energy Resources, Inc. and Gale E. Klappa and First Amendment and Assignment to SCS. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)87.)

(a) 78 - Deferred Compensation Agreement between SOUTHERN, Southern Energy Resources, Inc. and S. Marce Fuller. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)88.)

* (a) 79 - Amended and Restated Change in Control Agreement between SOUTHERN, GULF and Travis J. Bowden.

* (a) 80 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and A. W. Dahlberg.

* (a) 81 - Amended and Restated Change in Control Agreement between SOUTHERN, MISSISSIPPI and Dwight H. Evans.

(a) 82 - Change in Control Agreement between SOUTHERN, ALABAMA and Banks Harry Farris. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1998, File No. 1-3526 as Exhibit 10(a)88.)

* (a) 83 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and Henry Allen Franklin.

* (a) 84 - Amended and Restated Change in Control Agreement between SOUTHERN, Southern Nuclear and William G. Hairston, III.

* (a) 85 - Amended and Restated Change in Control Agreement between SOUTHERN, ALABAMA and Elmer B. Harris.

* (a) 86 - Amended and Restated Change in Control Agreement between SOUTHERN, SAVANNAH and G. Edison Holland, Jr.

* (a) 87 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and C. Alan Martin.

* (a) 88 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and Charles Douglas McCrary.

* (a) 89 - Amended and Restated Change in Control Agreement between SOUTHERN, GEORGIA and David M. Ratcliffe.

* (a) 90 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and Stephen A. Wakefield.

* (a) 91 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and W. Lawrence Westbrook.

* (a) 92 - Amended and Restated Change in Control Agreement between SOUTHERN, SCS and Gale E. Klappa.

(a) 93 - Change in Control Agreement between SOUTHERN, Southern Energy Resources, Inc. and S. Marce Fuller and First Amendment thereto. (Designated in SOUTHERN's Form 10-K for the year ended December 31, 1999, File No. 1-3526, as Exhibit 10(a)103.)

* (a) 94 - Deferred Compensation Agreement between SOUTHERN and William L. Westbrook.

* (a) 95 - Deferred Compensation Agreement between SOUTHERN and Alfred W. Dahlberg, III.

* (a) 96 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000.

* (a) 97 - Change in Control Agreement between SOUTHERN, SCS and Robert H. Haubein, Jr..

* (a) 98 - Deferred Compensation Agreement between SOUTHERN, SCS and Stephen A. Wakefield.

* (a) 99 - Deferred Compensation Agreement between SOUTHERN and Wayne T. Dalke.

* (a) 100 - Master Separation and Distribution Agreement dated as of September 1, 2000 between SOUTHERN and Mirant.

* (a) 101 - Indemnification and Insurance Matters Agreement dated as of September 1, 2000 between SOUTHERN and Mirant.

* (a) 102 - Tax Indemnification Agreement dated as of September 1, 2000 among SOUTHERN and its affiliated companies and Mirant and its affiliated companies.

* (a) 103 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear.

* (a) 104 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH.

* (a) 105 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH.

ALABAMA

(b) 1 - Service contracts dated as of January 1, 1984, between SCS and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SEGCO and SOUTHERN and Amendment No. 1 dated as of September 6, 1985 between SCS and SOUTHERN. See Exhibit 10(a)1 herein.

* (b) 2 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS. See Exhibit 10(a)6 herein.

(b) 3 - Agreement dated as of January 27, 1959, Amendment No. 1 dated as of October 27, 1982 and Amendment No. 2 dated November 4, 1993 and effective June 1, 1994, among SEGCO, ALABAMA and GEORGIA. See Exhibit 10(a)7 herein.

(b) 4 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)33 herein.

(b) 5 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)34 herein.

(b) 6 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)35 herein.

(b) 7 - Firm Power Purchase Contract between ALABAMA and AMEA. (Designated in Certificate of Notification, File No. 70-7212, as Exhibit B.)

(b) 8 - 1991 Firm Power Purchase Contract between ALABAMA and AMEA. (Designated in Form U-1, File No. 70-7873, as Exhibit B-1.)

(b) 9 - Purchase and Ownership Agreement for Joint Ownership Interest in the James H. Miller, Jr. Steam Electric Generating Plant Units One and Two dated November 18, 1988, between ALABAMA and AEC. See Exhibit 10(a)38 herein.

(b) 10 - Operating Agreement for Joint Ownership Interest in the James H. Miller, Jr. Steam Electric Generating Plant Units One and Two dated November 18, 1988, between ALABAMA and AEC. See Exhibit 10(a)39 herein.

(b) 11 - Long Term Transmission Service Agreement between Entergy Power, Inc. and ALABAMA, MISSISSIPPI and SCS. See Exhibit 10(a)47 herein.

(b) 12 - Operating Agreement for the Joseph M. Farley Nuclear Plant between ALABAMA and Southern Nuclear dated as of December 23, 1991. See Exhibit 10(a)51 herein.

\# * (b) 13 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2001. See Exhibit 10(a)52 herein.

(b) 14 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. See Exhibit 10(a)53 herein.

* (b) 15 - Amendment Number Six to The Southern Company Employee Savings Plan. See Exhibit 10(a)54 herein.

(b) 16 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. See Exhibit 10(a)55 herein.

* (b) 17 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan. See Exhibit 10(a)56 herein.

* (b) 18 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)57 herein.

* (b) 19 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000. See Exhibit 10(a)58 herein.

* (b) 20 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001. See Exhibit 10(a)61 herein.

(b) 21 - The Southern Company Outside Directors Pension Plan. See Exhibit 10(a)60 herein.

* (b) 22 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000. See Exhibit 10(a)63 herein.

(b) 23 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. See Exhibit 10(a)65 herein.

* (b) 24 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan. See Exhibit 10(a)66 herein.

* (b) 25 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)67 herein.

* (b) 26 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)68 herein.

* (b) 27 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000. See Exhibit 10(a)64 herein.

(b) 28 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. See Exhibit 10(a)69 herein.

* (b) 29 - Amendment Number Eight to The Southern Company Performance Sharing Plan. See Exhibit 10(a)70 herein.

* (b) 30 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)71 herein.

* (b) 31 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)72 herein.

(b) 32 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)73 herein.

(b) 33 - Change in Control Agreement between SOUTHERN, ALABAMA and Banks Harry Farris. See Exhibit 10(a)82 herein.

* (b) 34 - Amended and Restated Change in Control Agreement between SOUTHERN, ALABAMA and Elmer B. Harris. See Exhibit 10(a)85 herein.

(b) 35 - Supplemental Pension Agreement between ALABAMA, GULF and Travis J. Bowden. (Designated in ALABAMA's Form 10-K for the year ended December 31, 1998, File No. 1-3164, as Exhibit 10(b)40.)

* (b) 36 - Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated as of January 1, 2000.

* (b) 37 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000. See Exhibit 10(a)96 herein.

* (b) 38 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear. See Exhibit 10(a)103 herein.

* (b) 39 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(b) 104 herein.

* (b) 40 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)105 herein.

GEORGIA

(c) 1 - Service contracts dated as of January 1, 1984, between SCS and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SEGCO and SOUTHERN and Amendment No. 1 dated as of September 6, 1985, between SCS and SOUTHERN. See Exhibit 10(a)1 herein.

* (c) 2 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS. See Exhibit 10(a)6 herein.

(c) 3 - Agreement dated as of January 27, 1959, Amendment No. 1 dated as of October 27, 1982 and Amendment No. 2 dated November 4, 1993 and effective June 1, 1994, among SEGCO, ALABAMA and GEORGIA. See Exhibit 10(a)7 herein.

(c) 4 - Joint Committee Agreement dated as of August 27, 1976, among GEORGIA, OPC, MEAG and Dalton. See Exhibit 10(a)8 herein.

(c) 5 - Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement dated as of January 6, 1975, between GEORGIA and OPC. See Exhibit 10(a)9 herein.

(c) 6 - Edwin I. Hatch Nuclear Plant Operating Agreement dated as of January 6, 1975, between GEORGIA and OPC. See Exhibit 10(a)10 herein.

(c) 7 - Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between GEORGIA and OPC. See Exhibit 10(a)11 herein.

(c) 8 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of March 26, 1976, between GEORGIA and OPC. See Exhibit 10(a)12 herein.

(c) 9 - Plant Hal Wansley Operating Agreement dated as of March 26, 1976, between GEORGIA and OPC. See Exhibit 10(a)13 herein.

(c) 10 - Edwin I. Hatch Nuclear Plant Purchase and Ownership Participation Agreement dated as of August 27, 1976, between GEORGIA, MEAG and Dalton. See Exhibit 10(a)14 herein.

(c) 11 - Edwin I. Hatch Nuclear Plant Operating Agreement dated as of August 27, 1976, between GEORGIA, MEAG and Dalton. See Exhibit 10(a)15 herein.

(c) 12 - Alvin W. Vogtle Nuclear Units Number One and Two Purchase and Ownership Participation Agreement dated as of August 27, 1976 and Amendment No. 1 dated as of January 18, 1977, among GEORGIA, OPC, MEAG and Dalton. See Exhibit 10(a)16 herein.

(c) 13 - Alvin W. Vogtle Nuclear Units Number One and Two Operating Agreement dated as of August 27, 1976, among GEORGIA, OPC, MEAG and Dalton. See Exhibit 10(a)17 herein.

(c) 14 - Alvin W. Vogtle Nuclear Units Number One and Two Purchase, Amendment, Assignment and Assumption Agreement dated as of November 16, 1983, between GEORGIA and MEAG. See Exhibit 10(a)18 herein.

(c) 15 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of August 27, 1976, between GEORGIA and MEAG. See Exhibit 10(a)19 herein.

(c) 16 - Plant Hal Wansley Operating Agreement dated as of August 27, 1976, between GEORGIA and MEAG. See Exhibit 10(a)20 herein.

(c) 17 - Nuclear Operating Agreement between Southern Nuclear and GEORGIA dated as of July 1, 1993. See Exhibit 10(a)21 herein.

(c) 18 - Pseudo Scheduling and Services Agreement between GEORGIA and MEAG dated as of April 8, 1997. See Exhibit 10(a)22 herein.

(c) 19 - Plant Hal Wansley Purchase and Ownership Participation Agreement dated as of April 19, 1977, between GEORGIA and Dalton. See Exhibit 10(a)23 herein.

(c) 20 - Plant Hal Wansley Operating Agreement dated as of April 19, 1977, between GEORGIA and Dalton. See Exhibit 10(a)24 herein.

(c) 21 - Plant Robert W. Scherer Units Number One and Two Purchase and Ownership Participation Agreement dated as of May 15, 1980, Amendment No. 1 dated as of December 30, 1985, Amendment No. 2 dated as of July 1, 1986, Amendment No. 3 dated as of August 1, 1988 and Amendment No. 4 dated as of December 31, 1990, among GEORGIA, OPC, MEAG and Dalton. See Exhibit 10(a)25 herein.

(c) 22 - Plant Robert W. Scherer Units Number One and Two Operating Agreement dated as of May 15, 1980, Amendment No. 1 dated as of December 3, 1985 and Amendment No. 2 dated as of December 31, 1990, among GEORGIA, OPC, MEAG and Dalton. See Exhibit 10(a)26 herein.

(c) 23 - Plant Robert W. Scherer Purchase, Sale and Option Agreement dated as of May 15, 1980, between GEORGIA and MEAG. See Exhibit 10(a)27 herein.

(c) 24 - Plant Robert W. Scherer Purchase and Sale Agreement dated as of May 16, 1980, between GEORGIA and Dalton. See Exhibit 10(a)28 herein.

(c) 25 - Plant Robert W. Scherer Unit Number Three Purchase and Ownership Participation Agreement dated as of March 1, 1984, Amendment No. 1 dated as of July 1, 1986 and Amendment No. 2 dated as of August 1, 1988, between GEORGIA and GULF. See Exhibit 10(a)29 herein.

(c) 26 - Plant Robert W. Scherer Unit Number Three Operating Agreement dated as of March 1, 1984, between GEORGIA and GULF. See Exhibit 10(a)30 herein.

(c) 27 - Plant Robert W. Scherer Unit No. Four Amended and Restated Purchase and Ownership Participation Agreement by and among GEORGIA, FP&L and JEA dated as of December 31, 1990 and Amendment No. 1 dated as of June 15, 1994. See Exhibit 10(a)31 herein.

(c) 28 - Plant Robert W. Scherer Unit No. Four Operating Agreement by and among GEORGIA, FP&L and JEA dated as of December 31, 1990 and Amendment No. 1 dated as of June 15, 1994. See Exhibit 10(a)32 herein.

(c) 29 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)33 herein.

(c) 30 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)34 herein.

(c) 31 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)35 herein.

(c) 32 - Rocky Mountain Pumped Storage Hydroelectric Project Ownership Participation Agreement dated November 18, 1988, between OPC and GEORGIA. See Exhibit 10(a)36 herein.

(c) 33 - Rocky Mountain Pumped Storage Hydroelectric Project Operating Agreement dated November 18, 1988, between OPC and GEORGIA. See Exhibit 10(a)37 herein.

(c) 34 - Long Term Transaction Service Agreement between GEORGIA and OPC dated as of February 26, 1999. See Exhibit 10(a)41 herein.

(c) 35 - Revised and Restated Coordination Services Agreement between and among GEORGIA, OPC and Georgia Systems Operations Corporation dated as of September 10, 1997. See Exhibit 10(a)42 herein.

(c) 36 - Amended and Restated Nuclear Managing Board Agreement for Plant Hatch and Plant Vogtle among GEORGIA, OPC, MEAG and Dalton dated as of July 1, 1993. See Exhibit 10(a)43 herein.

(c) 37 - Integrated Transmission System Agreement, Power Sale and Coordination Umbrella Agreement between GEORGIA and OPC dated as of November 12, 1990. See Exhibit 10(a)44 herein.

(c) 38 - Revised and Restated Integrated Transmission System Agreement between GEORGIA and Dalton dated as of December 7, 1990. See Exhibit 10(a)45 herein.

(c) 39 - Revised and Restated Integrated Transmission System Agreement between GEORGIA and MEAG dated as of December 7, 1990. See Exhibit 10(a)46 herein.

(c) 40 - Plant Scherer Managing Board Agreement dated as of December 31, 1990 among GEORGIA, OPC, MEAG, Dalton, GULF, FP&L and JEA. See Exhibit 10(a)48 herein.

(c) 41 - Plant McIntosh Combustion Turbine Purchase and Ownership Participation Agreement between GEORGIA and SAVANNAH dated as of December 15, 1992. See Exhibit 10(a)49 herein.

(c) 42 - Plant McIntosh Combustion Turbine Operating Agreement between GEORGIA and SAVANNAH dated as of December 15, 1992. See Exhibit 10(a)50 herein.

(c) 43 - Certificate of Limited Partnership of Georgia Power Capital. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit B.)

(c) 44 - Amended and Restated Agreement of Limited Partnership of Georgia Power Capital, dated as of December 1, 1994. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit C.)

(c) 45 - Action of General Partner of Georgia Power Capital creating the Series A Preferred Securities. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit D.)

(c) 46 - Guarantee Agreement of GEORGIA dated as of December 1, 1994, for the benefit of the holders from time to time of the Series A Preferred Securities. (Designated in Certificate of Notification, File No. 70-8461, as Exhibit G.)

* (c) 47 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2001. See Exhibit 10(a)52 herein.

(c) 48 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. See Exhibit 10(a)53 herein.

* (c) 49 - Amendment Number Six to The Southern Company Employee Savings Plan. See Exhibit 10(a)54 herein.

(c) 50 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. See Exhibit 10(a)55 herein.

* (c) 51 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan. See Exhibit 10(a)56 herein.

* (c) 52 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)57 herein.

* (c) 53 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000. See Exhibit 10(a)58 herein.

* (c) 54 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001. See Exhibit 10(a)61 herein.

(c) 55 - The Southern Company Outside Directors Pension Plan. See Exhibit 10(a)60 herein.

* (c) 56 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000. See Exhibit 10(a)63 herein.

(c) 57 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. See Exhibit 10(a)65 herein.

* (c) 58 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan. See Exhibit 10(a)66 herein.

* (c) 59 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)67 herein.

* (c) 60 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)68 herein.

* (c) 61 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000. See Exhibit 10(a)64 herein.

(c) 62 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. See Exhibit 10(a)69 herein.

* (c) 63 - Amendment Number Eight to The Southern Company Performance Sharing Plan. See Exhibit 10(a)70 herein.

* (c) 64 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)71 herein.

* (c) 65 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)72 herein.

* (c) 66 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)73 herein.

(c) 67 - Deferred Compensation Agreement between SOUTHERN, GEORGIA and Henry Allen Franklin and First Amendment and Assignment to SCS. See Exhibit 10(a)74 herein.

(c) 68 - Deferred Compensation Agreement between SOUTHERN, GEORGIA and Warren Y. Jobe. See Exhibit 10(a)76 herein.

* (c) 69 - Amended and Restated Change in Control Agreement between SOUTHERN, GEORGIA and David M. Ratcliffe. See Exhibit 10(a)89 herein.

(c) 70 - Supplemental Pension Agreement between GEORGIA and Warren Y. Jobe. (Designated in GEORGIA's Form 10-K for the year ended December 31, 1998, File No. 1-6468, as Exhibit 10(c)77.)

* (c) 71 - Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective February 21, 2001.

* (c) 72 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000. See Exhibit 10(a)96 herein.

* (c) 73 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear. See Exhibit 10(a)103 herein.

* (c) 74 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)104 herein.

* (c) 75 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10 (a)105 herein.

GULF

(d) 1 - Service contracts dated as of January 1, 1984, between SCS and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SEGCO and SOUTHERN and Amendment No. 1 dated as of September 6, 1985, between SCS and SOUTHERN. See Exhibit 10(a)1 herein.

* (d) 2 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS. See Exhibit 10(a)6 herein.

(d) 3 - Plant Robert W. Scherer Unit Number Three Purchase and Ownership Participation Agreement dated as of March 1, 1984, Amendment No. 1 dated as of July 1, 1986 and Amendment No. 2 dated as of August 1, 1988, between GEORGIA and GULF. See Exhibit 10(a)29 herein.

(d) 4 - Plant Robert W. Scherer Unit Number Three Operating Agreement dated as of March 1, 1984, between GEORGIA and GULF. See Exhibit 10(a)30 herein.

(d) 5 - Plant Scherer Managing Board Agreement dated as of December 31, 1990 among GEORGIA, OPC, MEAG, Dalton, GULF, FP&L and JEA. See Exhibit 10(a)48 herein.

(d) 6 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)33 herein.

(d) 7 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)34 herein.

(d) 8 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)35 herein.

(d) 9 - Agreement between GULF and AEC, effective August 1, 1985. (Designated in GULF's Form 10-K for the year ended December 31, 1985, File No. 0-2429, as Exhibit 10(g).)

* (d) 10 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)52 herein.

(d) 11 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. See Exhibit 10(a)53 herein.

* (d) 12 - Amendment Number Six to The Southern Company Employee Savings Plan. See Exhibit 10(a)54 herein.

(d) 13 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. See Exhibit 10(a)55 herein.

* (d) 14 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan. See Exhibit 10(a)56 herein.

* (d) 15 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)57 herein.

* (d) 16 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000. See Exhibit 10(a)58 herein.

* (d) 17 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001. See Exhibit 10(a)61 herein.

(d) 18 - The Southern Company Outside Directors Pension Plan. See Exhibit 10(a)60 herein.

* (d) 19 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000. See Exhibit 10(a)63 herein.

(d) 20 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. See Exhibit 10(a)65 herein.

* (d) 21 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan. See Exhibit 10(a)66 herein.

* (d) 22 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)71 herein.

* (d) 23 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)72 herein.

* (d) 24 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)73 herein.

* (d) 25 - Amended and Restated Change in Control Agreement between SOUTHERN, GULF and Travis J. Bowden. See Exhibit 10(a)79 herein.

* (d) 26 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)67 herein.

* (d) 27 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)68 herein.

* (d) 28 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000. See Exhibit 10(a)64 herein.

(d) 29 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. See Exhibit 10(a)69 herein.

* (d) 30 - Amendment Number Eight to The Southern Company Performance Sharing Plan. See Exhibit 10(a)70 herein.

(d) 31 - Supplemental Pension Agreement between SAVANNAH, GULF and G. Edison Holland, Jr. (Designated in GULF's Form 10-K for the year ended December 31, 1998, File No. 0-2429, as Exhibit 10(d)35.)

(d) 32 - Supplemental Pension Agreement between ALABAMA, GULF and Travis J. Bowden. See Exhibit 10(b)35 herein.

* (d) 33 - Deferred Compensation Plan For Directors of Gulf Power Company, Amended and Restated Effective January 1, 2000 and First Amendment thereto.

* (d) 34 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000. See Exhibit 10(a)96 herein.

* (d) 35 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear. See Exhibit 10(a)103 herein.

* (d) 36 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)104 herein.

* (d) 37 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)105 herein.

MISSISSIPPI

(e) 1 - Service contracts dated as of January 1, 1984, between SCS and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SEGCO and SOUTHERN and Amendment No. 1 dated as of September 6, 1985, between SCS and SOUTHERN. See Exhibit 10(a)1 herein.

* (e) 2 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS. See Exhibit 10(a)6 herein.

(e) 3 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)33 herein.

(e) 4 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)34 herein.

(e) 5 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)35 herein.

(e) 6 - Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Gulf States and MISSISSIPPI. See Exhibit 10(a)40 herein.

(e) 7 - Long Term Transmission Service Agreement between Entergy Power, Inc. and ALABAMA, MISSISSIPPI and SCS. See Exhibit 10(a)47 herein.

* (e) 8 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2001. See Exhibit 10(a)52 herein.

(e) 9 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. See Exhibit 10(a)53 herein.

* (e) 10 - Amendment Number Six to The Southern Company Employee Savings Plan. See Exhibit 10(a)54 herein.

(e) 11 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. See Exhibit 10(a)55 herein.

* (e) 12 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan. See Exhibit 10(a)56 herein.

(e) 13 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)57 herein.

* (e) 14 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000. See Exhibit 10(a)58 herein.

* (e) 15 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001. See Exhibit 10(a)61 herein.

(e) 16 - The Southern Company Outside Directors Pension Plan. See Exhibit 10(a)60 herein.

* (e) 17 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000. See Exhibit 10(a)63 herein.

(e) 18 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. See Exhibit 10(a)65 herein.

* (e) 19 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan. See Exhibit 10(a)66 herein.

* (e) 20 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)71 herein.

* (e) 21 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)72 herein.

* (e) 22 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)73 herein.

* (e) 23 - Amended and Restated Change in Control Agreement between SOUTHERN, MISSISSIPPI and Dwight H. Evans. See Exhibit 10(a)81 herein.

* (e) 24 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1,2000. See Exhibit 10(a)67 herein.

* (e) 25 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)68 herein.

* (e) 26 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000. See Exhibit 10(a)64 herein.

(e) 27 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. See Exhibit 10(a)69 herein.

* (e) 28 - Amendment Number Eight to The Southern Company Performance Sharing Plan. See Exhibit 10(a)70 herein.

(e) 29 - Deferred Compensation Plan for Directors of Mississippi Power Company, Amended and Restated Effective January 1, 2000. (Designated in MISSISSIPPI's Form 10-K for the year ended December 31, 1999, File No. 0-6849, as Exhibit 10(e)37.)

* (e) 30 - Amendment Number One to the Deferred Compensation Plan for Directors of Mississippi Power Company.

* (e) 31 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000. See Exhibit 10(a)96 herein.

* (e) 32 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear. See Exhibit 10(a)103 herein.

* (e) 33 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)104 herein.

* (e) 34 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)105 herein.

SAVANNAH

(f) 1 - Service contract dated as of March 3, 1988, between SCS and SAVANNAH. See Exhibit 10(a)3 herein.

* (f) 2 - Interchange contract dated February 17, 2000, between ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, SPC and SCS. See Exhibit 10(a)6 herein.

(f) 3 - Unit Power Sales Agreement dated July 19, 1988, between FPC and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)33 herein.

(f) 4 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)34 herein.

(f) 5 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH and SCS. See Exhibit 10(a)35 herein.

(f) 6 - Plant McIntosh Combustion Turbine Purchase and Ownership Participation Agreement between GEORGIA and SAVANNAH dated as of December 15, 1992. See Exhibit 10(a)49 herein.

(f) 7 - Plant McIntosh Combustion Turbine Operating Agreement between GEORGIA and SAVANNAH dated December 15, 1992. See Exhibit 10(a)50 herein.

* (f) 8 - The Southern Company Executive Productivity Improvement Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)52 herein.

(f) 9 - The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Five. See Exhibit 10(a)53 herein.

* (f) 10 - Amendment Number Six to The Southern Company Employee Savings Plan. See Exhibit 10(a)54 herein.

(f) 11 - The Southern Company Employee Stock Ownership Plan, Amended and Restated effective January 1, 1997 and all amendments thereto through Amendment Number Three. See Exhibit 10(a)55 herein.

* (f) 12 - Amendment Number Four to The Southern Company Employee Stock Ownership Plan. See Exhibit 10(a)56 herein.

* (f) 13 - Supplemental Executive Retirement Plan of SAVANNAH, Amended and Restated effective October 26, 2000.

* (f) 14 - Deferred Compensation Plan for Key Employees of SAVANNAH, Amended and Restated effective October 26, 2000.

(f) 15 - The Southern Company Performance Pay Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)57 herein.

* (f) 16 - Southern Company Performance Pay Plan (Shareholder Approved) effective January 1, 2000. See Exhibit 10(a)58 herein.

(f) 17 - The Southern Company Outside Directors Pension Plan. See Exhibit 10(a)60 herein.

* (f) 18 - Deferred Compensation Plan for Directors of SAVANNAH, Amended and Restated effective October 26, 2000.

* (f) 19 - Outside Directors Stock Plan for Subsidiaries of The Southern Company, Amended and Restated effective January 1, 2000. See Exhibit 10(a)63 herein.

(f) 20 - The Southern Company Pension Plan, effective as of January 1, 1997 and all amendments thereto through Amendment Number Four. See Exhibit 10(a)65 herein.

* (f) 21 - Amendment Number Five and Amendment Number Six to The Southern Company Pension Plan. See Exhibit 10(a)66 herein.

* (f) 22 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)76 herein.

* (f) 23 - Southern Company Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)72 herein.

* (f) 24 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)73 herein.

* (f) 25 - Amended and Restated Change in Control Agreement between SOUTHERN, SAVANNAH and G. Edison Holland, Jr. See Exhibit 10(a)86 herein.

* (f) 26 - The Southern Company Deferred Compensation Plan, Amended and Restated effective February 23, 2001. See Exhibit 10(a)61 herein.

* (f) 27 - The Southern Company Performance Stock Plan, Amended and Restated effective January 1, 2000. See Exhibit 10(a)67 herein.

* (f) 28 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective July 10, 2000. See Exhibit 10(a)68 herein.

* (f) 29 - The Southern Company Performance Dividend Plan, Amended and Restated effective December 11, 2000. See Exhibit 10(a)64 herein.

(f) 30 - The Southern Company Performance Sharing Plan effective January 1, 1997 and all amendments thereto through Amendment Number Seven. See Exhibit 10(a)69 herein.

* (f) 31 - Amendment Number Eight to The Southern Company Performance Sharing Plan. See Exhibit 10(a)70 herein.

(f) 32 - Supplemental Pension Agreement between SAVANNAH, GULF and G. Edison Holland, Jr. See Exhibit 10(d)31 herein.

* (f) 33 - Southern Company Change in Control Benefit Plan Determination Policy, effective July 10, 2000. See Exhibit 10(a)96 herein.

* (f) 34 - Agreement for supplemental pension benefits between SAVANNAH and William Miles Greer.

* (f) 35 - Agreement crediting additional service between SAVANNAH and William Miles Greer.

* (f) 36 - Southern Company Deferred Compensation Trust Agreement dated as of January 1, 2001 between Wachovia Bank, N.A., SOUTHERN, SCS, ALABAMA, GEORGIA, GULF, MISSISSIPPI, SAVANNAH, Southern Communications, Energy Solutions, Mirant and Southern Nuclear. See Exhibit 10(a)103 herein.

* (f) 37 - Deferred Stock Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)104 herein.

* (f) 38 - Deferred Cash Compensation Trust Agreement for Directors of SOUTHERN and its subsidiaries, dated as of January 1, 2000, between Wachovia Bank, N.A, SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI, and SAVANNAH. See Exhibit 10(a)105 herein.

(21) Subsidiaries of Registrants

SOUTHERN

* (a) - Subsidiaries of Registrant is contained herein at page IV-5.

ALABAMA

* (b) - Subsidiaries of Registrant is contained herein at page IV-5.

GEORGIA

* (c) - Subsidiaries of Registrant is contained herein at page IV-5.

GULF

* (d) - Subsidiaries of Registrant is contained herein at page IV-5.

MISSISSIPPI

* (e) - Subsidiaries of Registrant is contained herein at page IV-5.

SAVANNAH

* (f) - Subsidiaries of Registrant is contained herein at page IV-5.

(23) Consents of Experts and Counsel

SOUTHERN

* (a) - The consent of Arthur Andersen LLP is contained herein at page IV-6.

ALABAMA

* (b) - The consent of Arthur Andersen LLP is contained herein at page IV-7.

GEORGIA

* (c) - The consent of Arthur Andersen LLP is contained herein at page IV-8.

GULF

* (d) - The consent of Arthur Andersen LLP is contained herein at page IV-9.

MISSISSIPPI

* (e) - The consent of Arthur Andersen LLP is contained herein at page IV-10.

SAVANNAH

* (f) - The consent of Arthur Andersen LLP is contained herein at page IV-11.

(24) Powers of Attorney and Resolutions

SOUTHERN

* (a) - Power of Attorney and resolution.

ALABAMA

* (b) - Power of Attorney and resolution.

GEORGIA

* (c) - Power of Attorney and resolution.

GULF

* (d) - Power of Attorney and resolution.

MISSISSIPPI

* (e) - Power of Attorney and resolution.

SAVANNAH

* (f) - Power of Attorney and resolution.

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

FORM 10-Q
(X) QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarter Ended March 31, 2001
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from _____to_____

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 270 Peachtree Street, N.W. Atlanta, Georgia 30303 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
0-2429	**Gulf Power Company** (A Maine Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
0-6849	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
1-5072	**Savannah Electric and Power Company** (A Georgia Corporation) 600 East Bay Street Savannah, Georgia 31401 (912) 644-7171	58-0418070

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes X No____

Registrant	Description of Common Stock	Shares Outstanding at April 30, 2001
The Southern Company	**Par Value $5 Per Share**	**685,024,375**
Alabama Power Company	**Par Value $40 Per Share**	**5,608,955**
Georgia Power Company	**No Par Value**	**7,761,500**
Gulf Power Company	**No Par Value**	**992,717**
Mississippi Power Company	**Without Par Value**	**1,121,000**
Savannah Electric and Power Company	**Par Value $5 Per Share**	**10,844,635**

This combined Form 10-Q is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

INDEX TO QUARTERLY REPORT ON FORM 10-Q
March 31, 2001

DEFINITIONS

TERM	MEANING
ALABAMA	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
ECO Plan	Environmental Compliance Overview Plan
Energy Act	Energy Policy Act of 1992
EPA	U. S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	Combined Annual Report on Form 10-K of SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH for the year ended December 31, 2000
GEORGIA	Georgia Power Company
GULF	Gulf Power Company
integrated Southeast utilities	ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH
Mirant	Mirant Corporation (formerly Southern Energy Inc.)
MISSISSIPPI	Mississippi Power Company
Mobile Energy	Mobile Energy Services Company, L.L.C. and Mobile Energy Services Holdings, Inc.
PEP	Performance Evaluation Plan
PSC	Public Service Commission
RTO	Regional Transmission Organization
SAVANNAH	Savannah Electric and Power Company
SCS	Southern Company Services, Inc.
SEC	Securities and Exchange Commission
SOUTHERN	The Southern Company
SOUTHERN system	SOUTHERN, integrated Southeast utilities and other subsidiaries

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking and historical information. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "should," "expects," "plans," "anticipates," "believes," "estimates," "predicts," "potential" or "continue" or the negative of these terms or other comparable terminology. The registrants caution 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 SOUTHERN and its subsidiaries are subject, as well as changes in application of existing laws and regulations; current and future litigation, including the pending EPA civil action against certain of the integrated Southeast utilities and the race discrimination litigation against certain of SOUTHERN's subsidiaries; the effects, extent and timing of the entry of additional competition in the markets of SOUTHERN's subsidiaries; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial; internal restructuring or other restructuring options that may be pursued by SOUTHERN; state and federal rate regulation in the United States; political, legal and economic conditions and developments in the United States; financial market conditions and the results of financing efforts; the impact of fluctuations in commodity prices, interest rates and customer demand; weather and other natural phenomena; the performance of projects undertaken by the non-traditional business and the success of efforts to invest in and develop new opportunities; the timing and acceptance of SOUTHERN's new product and service offerings; the ability of SOUTHERN to obtain additional generating capacity at competitive prices; and other factors discussed elsewhere herein and in other reports (including Form 10-K) filed from time to time with the SEC.

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THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Revenues:		
Retail sales	**$1,882,478**	$1,782,708
Sales for resale	**260,046**	177,929
Other revenues	**126,994**	90,966
Total operating revenues	**2,269,518**	2,051,603
Operating Expenses:		
Operation --		
Fuel	**607,481**	524,073
Purchased power	**114,026**	74,429
Other operations	**405,865**	387,363
Maintenance	**225,857**	210,942
Depreciation and amortization	**303,666**	291,674
Taxes other than income taxes	**137,309**	135,179
Total operating expenses	**1,794,204**	1,623,660
Operating Income	**475,314**	427,943
Other Income:		
Interest income	**5,455**	8,967
Equity in earnings of unconsolidated subsidiaries	**(2,697)**	(5,778)
Other, net	**2,549**	11,654
Earnings From Continuing Operations Before Interest and Income Taxes	**480,621**	442,786
Interest and Other:		
Interest expense, net	**144,888**	152,947
Distributions on capital and preferred securities of subsidiaries	**42,241**	42,242
Preferred dividends of subsidiaries	**4,805**	4,695
Total interest and other	**191,934**	199,884
Earnings From Continuing Operations Before Income Taxes	**288,687**	242,902
Income taxes	**109,945**	91,747
Earnings From Continuing Operations Before Cumulative Effect of Accounting Change	**178,742**	151,155
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $477 thousand	**771**	-
Earnings From Continuing Operations	**179,513**	151,155
Earnings from discontinued operations, net of income taxes of $91,752 thousand and $(30,237) thousand for 2001 and 2000, respectively	**140,032**	94,289
Consolidated Net Income	**$ 319,545**	$ 245,444
Common Stock Data:		
Basic and diluted earnings per share of common stock --		
Earnings per share from continuing operations	**$0.26**	$0.23
Earnings per share from discontinued operations	**$0.21**	$0.15
Consolidated Basic and Diluted Earnings Per Share	**$0.47**	$0.38
Average number of shares of common stock outstanding (in thousands)	**682,575**	653,134
Cash dividends paid per share of common stock	**$0.335**	$0.335

The accompanying notes as they relate to SOUTHERN are an integral part of these statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Operating Activities:		
Consolidated net income	**$319,545**	$245,444
Adjustments to reconcile consolidated net income		
to net cash provided from operating activities --		
Less income from discontinued operations	**140,032**	94,289
Depreciation and amortization	**327,793**	355,889
Deferred income taxes and investment tax credits	**(30,355)**	(5,818)
Equity in earnings of unconsolidated subsidiaries	**2,697**	5,778
Other, net	**(344,997)**	(89,667)
Changes in certain current assets and liabilities --		
Receivables, net	**328,409**	230,742
Fossil fuel stock	**(134,413)**	(1,767)
Materials and supplies	**533**	(9,897)
Accounts payable	**(209,598)**	(106,333)
Other	**1,813**	(235,021)
Net cash provided from operating activities of continuing operations	**121,395**	295,061
Investing Activities:		
Gross property additions	**(670,183)**	(455,126)
Other	**(76,900)**	(99,292)
Net cash used for investing activities of continuing operations	**(747,083)**	(554,418)
Financing Activities:		
Increase (decrease) in notes payable, net	**197,365**	599,806
Proceeds --		
Other long-term debt	**458,582**	420,737
Common stock	**87,880**	43
Redemptions --		
First mortgage bonds	**(200,000)**	(200,000)
Other long-term debt	**(6,145)**	(52,146)
Preferred stock	**-**	(279)
Common stock repurchased	**-**	(414,298)
Payment of common stock dividends	**(228,320)**	(220,557)
Other	**(5,777)**	(10,700)
Net cash provided from financing activities of continuing operations	**303,585**	122,606
Cash provided by discontinued operations	**302,668**	69,765
Net Decrease in Cash and Cash Equivalents	**(19,435)**	(66,986)
Cash and Cash Equivalents at Beginning of Year	**199,191**	153,955
Cash and Cash Equivalents at End of Year	**$179,756**	$86,969
Supplemental Cash Flow Information From Continuing Operations:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$144,450**	$169,384
Income taxes (net of refunds)	**($4,069)**	$3,126

The accompanying notes as they relate to SOUTHERN are an integral part of these statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS

Assets	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 179,756**	$ 199,191
Special deposits	**10,258**	5,895
Receivables, less accumulated provisions for uncollectible accounts of $25,143 thousand at March 31, 2001 and $21,799 thousand at December 31, 2000	**1,019,388**	1,311,457
Under recovered retail fuel clause revenue	**351,492**	418,077
Fossil fuel stock, at average cost	**329,619**	195,206
Materials and supplies, at average cost	**506,892**	507,425
Other	**253,716**	187,948
Total current assets	**2,651,121**	2,825,199
Property, Plant, and Equipment:		
In service	**34,451,062**	34,187,808
Less accumulated depreciation	**14,525,469**	14,348,763
	19,925,593	19,839,045
Nuclear fuel, at amortized cost	**196,809**	214,620
Construction work in progress	**1,917,697**	1,568,737
Total property, plant, and equipment	**22,040,099**	21,622,402
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**670,355**	689,561
Net assets of discontinued operations	**3,157,861**	3,320,497
Leveraged leases	**610,864**	595,952
Other	**219,004**	165,332
Total other property and investments	**4,658,084**	4,771,342
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**951,018**	956,673
Prepaid pension costs	**528,906**	498,279
Debt expense, being amortized	**76,266**	99,442
Premium on reacquired debt, being amortized	**275,148**	280,239
Other	**346,395**	308,082
Total deferred charges and other assets	**2,177,733**	2,142,715
Total Assets	**$31,527,037**	$31,361,658

The accompanying notes as they relate to SOUTHERN are an integral part of these statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED BALANCE SHEETS

Liabilities and Stockholders' Equity	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 467,756**	$ 67,324
Notes payable	**1,877,008**	1,679,643
Accounts payable	**632,840**	870,032
Customer deposits	**143,468**	139,798
Taxes accrued --		
Income taxes	**236,099**	87,731
Other	**119,173**	208,143
Interest accrued	**186,832**	120,770
Vacation pay accrued	**118,158**	118,710
Other	**340,886**	444,600
Total current liabilities	**4,122,220**	3,736,751
Long-term debt	**7,695,096**	7,842,491
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**4,074,455**	4,074,265
Deferred credits related to income taxes	**540,061**	551,259
Accumulated deferred investment tax credits	**656,135**	663,579
Employee benefits provisions	**492,704**	478,414
Prepaid capacity revenues	**52,634**	58,377
Other	**716,713**	651,805
Total deferred credits and other liabilities	**6,532,702**	6,477,699
Company or subsidiary obligated mandatorily redeemable capital and preferred securities	**2,246,250**	2,246,250
Cumulative preferred stock of subsidiaries	**368,126**	368,126
Common Stockholders' Equity:		
Common stock, par value $5 per share --		
Authorized -- 1 billion shares		
Issued -- March 31, 2001: 700,622,308 shares;		
-- December 31, 2000: 700,622,308 shares	**3,503,112**	3,503,112
Paid-in capital	**3,168,454**	3,153,461
Treasury, at cost -- March 31, 2001: 16,617,726 shares;		
-- December 31, 2000: 19,464,122 shares	**(465,288)**	(544,515)
Retained earnings	**4,763,406**	4,671,881
Accumulated other comprehensive income	**(407,041)**	(93,598)
Total common stockholders' equity	**10,562,643**	10,690,341
Total Liabilities and Stockholders' Equity	**$31,527,037**	$31,361,658

The accompanying notes as they relate to SOUTHERN are an integral part of these statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Consolidated net income	**$319,545**	$245,444
Other comprehensive income - continuing operations:		
Cumulative effect of accounting change	**466**	-
Current period changes in fair value	**1,324**	-
Related income tax benefits	**(683)**	-
Total other comprehensive income - Continuing operations	**1,107**	-
Other comprehensive income - discontinued operations:		
Cumulative effect of accounting change, net of income tax	**(249,246)**	-
Current period changes in fair value, net of income tax	**(103,962)**	-
Current period reclassifications to net income, net of income tax	**59,857**	-
Foreign currency translation adjustments and other, net of income tax	**(21,199)**	(2,918)
Total other comprehensive income - discontinued operations	**(314,550)**	(2,918)
CONSOLIDATED COMPREHENSIVE INCOME	**$ 6,102**	$242,526

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Balance at beginning of period - continuing operations	**$ 249**	$ -
Change in current period - continuing operations	**1,107**	249
BALANCE AT END OF PERIOD - Continuing Operations	**1,356**	249
Balance at beginning of period - discontinued operations	**(93,847)**	(92,395)
Change in current period - discontinued operations	**(314,550)**	(1,452)
BALANCE AT END OF PERIOD - Discontinued Operations	**(408,397)**	(93,847)
TOTAL ACCUMULATED OTHER COMPREHENSIVE INCOME	**($407,041)**	($93,598)

The accompanying notes as they relate to SOUTHERN are an integral part of these statements.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Effective April 2, 2001, SOUTHERN completed a spin off of its remaining ownership of 272 million Mirant shares to SOUTHERN's shareholders in a tax free distribution. Shares from the spin off were distributed at a rate of approximately 0.4 share of Mirant common stock for every share of SOUTHERN common stock held at the record date. As a result of the spin off, SOUTHERN's March 31, 2001 financial statements reflect Mirant as discontinued operations.

SOUTHERN is now focusing on three main businesses in the Southeast: its traditional business, represented by its five integrated Southeast utilities providing electric service in four states; a growing competitive generation business in the eight state "Super Southeast" region; and energy-related products and services for its retail customers.

Earnings

SOUTHERN's reported consolidated net income for the first quarter of 2001 was $320 million ($0.47 per share), compared to $245 million ($0.38 per share) for the corresponding period of 2000. Excluding Mirant's contributions, SOUTHERN's first quarter 2001 earnings from operations were $180 million ($0.26 per share), compared with $151 million ($0.23 per share) in the first quarter of 2000. The increase in earnings for the current quarter is primarily due to higher operating revenues partially offset by higher operating expenses.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease) First Quarter	
	(in thousands)	%
Retail sales	$99,770	5.6
Sales for resale	82,117	46.2
Other revenues	36,028	39.6
Fuel expense	83,408	15.9
Purchased power expense	39,597	53.2
Maintenance expense	14,915	7.1

Retail sales revenue. Excluding fuel revenues, which generally do not affect net income, retail sales revenue was up by $47 million in the first quarter of 2001 from the same period in 2000 due to a 0.9% increase in retail energy sales. Retail energy sales were higher during the current quarter due primarily to weather and growth in the number of customers served by the integrated Southeast utilities.

Sales for resale. The increase in this first quarter of 2001 from the same period in 2000 reflects increased demand for energy by non-affiliates. Since this energy is usually sold at variable cost, these transactions do not have a significant impact on earnings. Wholesale energy sales from Plant Dahlberg which went into service in the second quarter of 2000 also contributed to the sales for resale revenue increase in the first quarter of 2001.

Other revenues. During the first quarter of 2001, other revenues were higher than the amount recorded in the same period in 2000 due primarily to increased revenues from gas-fueled cogeneration steam facilities, higher revenues from transmission of electricity for others and pole attachment rentals and fuel clause adjustments. Revenues from cogeneration activities are generally offset by fuel expenses and do not have a significant impact on earnings. The fuel clause adjustments reflect the difference between recoverable costs and the amounts actually reflected in current rates; further, the recovery provisions generally equal related expenses and have no material effect on net income.

Fuel expense. For the first quarter of 2001, fuel expenses increased from the same period in 2000 due primarily to increased generation from gas-fueled plants at a time of higher natural gas prices. Since energy expenses are usually offset by energy revenues, these expenses do not have a significant impact on earnings.

Purchased power expense. This expense increased during the first quarter of 2001 from the same period in 2000 due primarily to higher costs associated with these purchases as well as increased demand related to the drought in GEORGIA's service area. Since energy expenses are usually offset by energy revenues, these expenses do not have a significant impact on earnings.

Maintenance expense. These expenses increased in the first quarter of 2001 when compared to the same period in 2000 due primarily to scheduled work performed at steam generating, transmission and distribution facilities.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors. The two major factors are the ability of the integrated Southeast utilities to achieve energy sales growth while containing cost in a more competitive environment; and the profitability of the new competitive market-based wholesale generating facilities being added. For additional information relating to the other businesses, see Item 1 - BUSINESS - "Other Business" in the Form 10-K. Also, reference is made to Note (B) in the "Notes to the Condensed Financial Statements" herein for information relating to the spin off of Mirant.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, SOUTHERN is positioning the business to meet the challenge of increasing competition. For additional information, see Item 1 - BUSINESS - "Competition" and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of SOUTHERN in the Form 10-K.

Compliance costs related to the Clean Air Act could affect earnings if such costs cannot be offset. For additional information about the Clean Air Act and other environmental issues, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" of SOUTHERN in the Form 10-K.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

Reference is also made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" and Note 3 to the financial statements of SOUTHERN in the Form 10-K for information on EPA litigation.

Reference is made to Notes (B) through (L) and (N) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential. Reference is also made to Part II - Item 1 - "Legal Proceedings" herein.

Adoption of New Accounting Standard

Effective January 1, 2001, SOUTHERN and its subsidiaries adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

Major changes in SOUTHERN's financial condition during the first three months of 2001 included $670 million used for gross property additions to utility plant. The funds for these additions and other capital requirements were from operations and other long-term debt. See SOUTHERN's Condensed Consolidated Statements of Cash Flows for further details. Reference is made to SOUTHERN's Condensed Consolidated Statements of Comprehensive Income herein for information relating to other comprehensive income.

Financing Activities

In February 2001, GEORGIA issued $350 million aggregate principal amount of senior notes consisting of $200 million of Series F 5.75% Senior Notes due January 31, 2003 and $150 million Series G 6.20% Senior Notes due February 1, 2006. The proceeds of the sale were applied to redeem $200 million of 6 5/8% Series First Mortgage Bonds due April 2003 and to repay a portion of GEORGIA's outstanding short-term indebtedness. Also in February 2001, GEORGIA issued $100 million of Series H 6.70% Senior Insured Quarterly Notes due March 1, 2011. The proceeds of this sale were used to repay an additional portion of GEORGIA's outstanding short-term indebtedness. In April 2001, ALABAMA sold, through a public authority, $10 million of variable rate demand revenue bonds due April 1, 2031. In May 2001, GEORGIA issued $90 million of Series I 5.25% Senior Notes due May 8, 2003. The proceeds of this sale will be used to redeem in June 2001 the $75 million outstanding principal amount of GEORGIA's 6.35% Series, First Mortgage Bonds due August 1, 2003 and to repay a portion of GEORGIA's outstanding short-term indebtedness.

The market price of SOUTHERN's common stock at March 31, 2001 with Mirant was $35.09 per share and the book value was $15.37 per share, representing a market-to-book ratio of 228%, compared to $33.25, $15.69 and 212%, respectively, at the end of 2000. The dividend for the first quarter of 2001 was $0.335 per share.

Capital Requirements

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Capital Requirements", "Other Capital Requirements" and "Environmental Matters" of SOUTHERN in the Form 10-K for a description of the SOUTHERN system's capital requirements for its construction program, sinking fund requirements and maturing debt, and environmental compliance efforts. Approximately $468 million will be required by March 31, 2002 for redemptions and maturities of long-term debt. Also, the integrated Southeast utilities plan to continue, to the extent possible, a program to retire higher-cost debt and replace these securities with lower-cost capital.

Sources of Capital

In addition to the financing activities previously described, SOUTHERN may require additional equity capital during the remainder of the year. The amounts and timing of additional equity capital to be raised in 2001, as well as in subsequent years, will be contingent on SOUTHERN's investment opportunities. The integrated Southeast utilities plan to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon market conditions and regulatory approval. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, the SOUTHERN system had at March 31, 2001 approximately $180 million of cash and cash equivalents and approximately $5.1 billion of unused credit arrangements with banks. These unused credit arrangements also provide liquidity support to variable rate pollution control bonds and commercial paper programs. SOUTHERN's integrated Southeast utilities may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of each of the integrated Southeast utilities. At March 31, 2001, the SOUTHERN system had short-term notes payable outstanding of $1.9 billion. Management believes that the need for working capital can be adequately met by utilizing lines of credit without maintaining large cash balances.

PART I

Item 3. Quantitative And Qualitative Disclosures About Market Risk.

Reference is made to MANAGEMENT'S DISCUSSION AND ANALYSIS - "Market Price Risk" and Note 1 to the financial statements of SOUTHERN in Item 8 of the Form 10-K. Additional reference is made to Notes (C), (D) and (J) in the "Notes to the Condensed Financial Statements" contained herein for additional information regarding commodity-related marketing and price risk management activities.

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ALABAMA POWER COMPANY

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Revenues:		
Retail sales	**$634,772**	$606,126
Sales for resale --		
Non-affiliates	**110,462**	96,131
Affiliates	**75,133**	28,669
Other revenues	**29,635**	15,251
Total operating revenues	**850,002**	746,177
Operating Expenses:		
Operation --		
Fuel	**259,455**	195,074
Purchased power --		
Non-affiliates	**34,309**	18,872
Affiliates	**35,986**	26,865
Other	**111,002**	112,246
Maintenance	**76,360**	76,834
Depreciation and amortization	**95,517**	90,472
Taxes other than income taxes	**57,346**	54,152
Total operating expenses	**669,975**	574,515
Operating Income	**180,027**	171,662
Other Income:		
Interest income	**3,486**	5,926
Equity in earnings of unconsolidated subsidiaries	**1,055**	859
Other, net	**(3,130)**	(1,082)
Earnings Before Interest and Income Taxes	**181,438**	177,365
Interest and Other:		
Interest expense, net	**57,821**	58,908
Distributions on preferred securities of subsidiary	**6,356**	6,336
Total interest and other, net	**64,177**	65,244
Earnings Before Income Taxes	**117,261**	112,121
Income taxes	**43,610**	40,641
Net Income Before Cumulative Effect of Accounting Change	**73,651**	71,480
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $215 thousand	**353**	-
Net Income	**74,004**	71,480
Dividends on Preferred Stock	**4,052**	3,968
Net Income After Dividends on Preferred Stock	**$ 69,952**	$ 67,512

The accompanying notes as they relate to ALABAMA are an integral part of these condensed statements.

ALABAMA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Operating Activities:		
Net income	**$74,004**	$71,480
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization	**106,491**	101,947
Deferred income taxes and investment tax credits, net	**2,656**	(2,423)
Other, net	**(33,180)**	(22,451)
Changes in certain current assets and liabilities --		
Receivables, net	**131,403**	40,702
Fossil fuel stock	**(31,782)**	(8,814)
Materials and supplies	**4,602**	(7,327)
Accounts payable	**(135,845)**	(48,113)
Energy cost recovery, retail	**30,624**	23,037
Other	**(22,531)**	(17,973)
Net cash provided from operating activities	**126,442**	130,065
Investing Activities:		
Gross property additions	**(194,434)**	(193,894)
Other	**5,367**	(2,365)
Net cash used for investing activities	**(189,067)**	(196,259)
Financing Activities:		
Increase in notes payable, net	**164,996**	274,871
Redemptions --		
First mortgage bonds	**-**	(100,000)
Other long-term debt	**(1,179)**	(1,685)
Payment of preferred stock dividends	**(3,699)**	(4,028)
Payment of common stock dividends	**(101,200)**	(103,600)
Other	**191**	(20)
Net cash provided from financing activities	**59,109**	65,538
Net Change in Cash and Cash Equivalents	**(3,516)**	(656)
Cash and Cash Equivalents at Beginning of Period	**14,247**	19,475
Cash and Cash Equivalents at End of Period	**$ 10,731**	$ 18,819
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$47,083**	$50,316
Income taxes (net of refunds)	**$4,676**	$529

The accompanying notes as they relate to ALABAMA are an integral part of these condensed statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS

Assets	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 10,731**	$ 14,247
Receivables --		
Customer accounts receivable	**277,968**	337,870
Under recovered retail fuel clause revenue	**207,193**	237,817
Other accounts and notes receivable	**40,457**	60,315
Affiliated companies	**43,798**	95,704
Accumulated provision for uncollectible accounts	**(5,974)**	(6,237)
Fossil fuel stock, at average cost	**92,397**	60,615
Materials and supplies, at average cost	**173,697**	178,299
Other	**97,214**	52,624
Total current assets	**937,481**	1,031,254
Property, Plant, and Equipment:		
In service	**12,557,523**	12,431,575
Less accumulated provision for depreciation	**5,184,726**	5,107,822
	7,372,797	7,323,753
Nuclear fuel, at amortized cost	**87,922**	94,050
Construction work in progress	**796,709**	744,974
Total property, plant, and equipment	**8,257,428**	8,162,777
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**39,922**	38,623
Nuclear decommissioning trusts	**304,840**	313,895
Other	**14,039**	13,612
Total other property and investments	**358,801**	366,130
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**344,826**	345,550
Prepaid pension costs	**282,302**	268,259
Debt expense, being amortized	**8,409**	8,758
Premium on reacquired debt, being amortized	**74,029**	76,020
Department of Energy assessments	**24,588**	24,588
Other	**104,345**	95,772
Total deferred charges and other assets	**838,499**	818,947
Total Assets	**$10,392,209**	$10,379,108

The accompanying notes as they relate to ALABAMA are an integral part of these condensed statements.

ALABAMA POWER COMPANY
CONDENSED BALANCE SHEETS

Liabilities and Stockholders' Equity	**At March 31, 2001 (Unaudited)**	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 846**	$ 844
Notes payable	**446,339**	281,343
Accounts payable --		
Affiliated	**105,944**	124,534
Other	**93,295**	209,205
Customer deposits	**38,217**	36,814
Taxes accrued --		
Income taxes	**111,109**	65,505
Other	**37,329**	19,471
Interest accrued	**46,188**	33,186
Vacation pay accrued	**31,711**	31,711
Other	**51,097**	97,743
Total current liabilities	**962,075**	900,356
Long-term debt	**3,425,059**	3,425,527
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**1,398,836**	1,401,424
Deferred credits related to income taxes	**217,894**	222,485
Accumulated deferred investment tax credits	**246,516**	249,280
Employee benefits provisions	**87,792**	84,816
Prepaid capacity revenues	**52,634**	58,377
Other	**172,058**	176,559
Total deferred credits and other liabilities	**2,175,730**	2,192,941
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes	**347,000**	347,000
Cumulative preferred stock	**317,512**	317,512
Common Stockholder's Equity:		
Common stock, par value $40 per share --		
Authorized - 6,000,000 shares		
Outstanding - 5,608,955 shares		
Par value	**224,358**	224,358
Paid-in capital	**1,743,371**	1,743,363
Premium on preferred stock	**99**	99
Retained earnings	**1,197,005**	1,227,952
Total common stockholder's equity	**3,164,833**	3,195,772
Total Liabilities and Stockholder's Equity	**$10,392,209**	$10,379,108

The accompanying notes as they relate to ALABAMA are an integral part of these condensed statements.

ALABAMA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Earnings

ALABAMA's net income after dividends on preferred stock for the first quarter of 2001 was $70.0 million compared to $67.5 million for the corresponding period of 2000. The increase in first quarter 2001 earnings was primarily due to increased operating revenues which were partially offset by higher operating expenses.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease) First Quarter (in thousands)	%
Retail sales	$28,646	4.7
Sales for resale - non-affiliates	14,331	14.9
Sales for resale - affiliates	46,464	162.1
Other revenues	14,384	94.3
Fuel expense	64,381	33.0
Purchased power - non-affiliates	15,437	81.8
Purchased power - affiliates	9,121	34.0

Retail sales. Excluding fuel revenues, which generally do not affect net income, retail sales revenue was up by $4.3 million or 1% during the first quarter of 2001 when compared to the same period in 2000. Energy sales to industrial customers decreased as a result of a slower economy during the first quarter of 2001; however, energy sales to residential and commercial customers increased due to colder weather.

Sales for resale - non-affiliates. For the first quarter of 2001 these sales were higher when compared to the same period in 2000 due to increased demand for energy by non-affiliates. These transactions did not have a significant impact on earnings since the energy is usually sold at variable cost.

Sales for resale - affiliates and Purchased power - affiliates. Revenues from sales for resale to affiliated companies within the SOUTHERN system, as well as purchases of energy, will vary from period to period 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 revenues. This increase in the first quarter of 2001 when compared to the same period in 2000 is primarily due to an increase in revenue from gas-fueled cogeneration steam facilities. Since cogeneration steam revenues are generally offset by fuel expenses, these revenues did not have a significant impact on earnings.

Fuel expense. Increased generation from gas-fueled plants at a time of increased natural gas prices resulted in higher fuel expense for the first quarter of 2001 when compared to the same period in 2000. Since energy expenses are generally offset by energy revenues, these expenses did not have a significant impact on earnings.

Purchased power - non-affiliates. Purchased power from non-affiliates increased for the first quarter of 2001 when compared to the corresponding period in 2000 due primarily to higher costs associated with these energy purchases. These expenses do not have a significant impact on earnings since energy expenses are generally offset by energy revenues.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from weather to energy sales growth to a less regulated, more competitive environment.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, ALABAMA is positioning the business to meet the challenge of increasing competition. For additional information, see Item 1 - BUSINESS - "Competition" and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of ALABAMA in the Form 10-K.

Compliance costs related to the Clean Air Act could affect earnings if such costs cannot be offset. For additional information about the Clean Air Act and other environmental issues, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" of ALABAMA in the Form 10-K.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS – "Environmental Matters" and Note 3 to the financial statements of ALABAMA in the Form 10-K for information on EPA litigation.

Reference is made to Notes (C) through (G) and (L) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential.

Adoption of New Accounting Standard

Effective January 1, 2001, ALABAMA adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

Major changes in ALABAMA's financial condition during the first three months of 2001 included the addition of approximately $194 million to utility plant. The funds for these additions and other capital requirements were derived primarily from operating activities. See ALABAMA's Condensed Statements of Cash Flows for further details.

Financing Activities

In April 2001, ALABAMA sold, through a public authority, $10 million of variable rate demand revenue bonds due April 1, 2031. ALABAMA plans to continue, to the extent possible, a program to retire higher-cost debt and replace these obligations with lower-cost capital.

Capital Requirements

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS of ALABAMA under "Capital Requirements," "Other Capital Requirements" and "Environmental Matters" in the Form 10-K for a description of ALABAMA's capital requirements for its construction program, maturing debt and environmental compliance efforts.

Sources of Capital

In addition to the financing activities previously described herein, ALABAMA plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon maintenance of adequate earnings, regulatory approval, prevailing market conditions and other factors. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, ALABAMA had at March 31, 2001 approximately $11 million of cash and cash equivalents, unused committed lines of credit of approximately $925 million (including $418 million of such lines under which borrowings may be made only to fund purchase obligations relating to variable rate pollution control bonds) and an extendible commercial note program. ALABAMA may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of ALABAMA. ALABAMA has regulatory authority for up to $750 million of short-term borrowings. At March 31, 2001, ALABAMA had outstanding $300.7 million of commercial paper, $89.6 million of extendible commercial notes, and $56 million in notes payable to banks.

GEORGIA POWER COMPANY

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Revenues:		
Retail sales	**$949,145**	$909,028
Sales for resale --		
Non-affiliates	**87,591**	43,689
Affiliates	**35,777**	11,933
Other revenues	**35,516**	26,989
Total operating revenues	**1,108,029**	991,639
Operating Expenses:		
Operation --		
Fuel	**228,692**	210,907
Purchased power --		
Non-affiliates	**54,105**	43,110
Affiliates	**79,295**	47,740
Other	**175,574**	158,983
Maintenance	**106,665**	98,133
Depreciation and amortization	**164,249**	157,767
Taxes other than income taxes	**50,101**	51,613
Total operating expenses	**858,681**	768,253
Operating Income	**249,348**	223,386
Other Income (Expense):		
Interest income	**602**	408
Equity in earnings of unconsolidated subsidiaries	**1,009**	853
Other, net	**(8,366)**	(6,225)
Earnings Before Interest and Income Taxes	**242,593**	218,422
Interest Charges and Other:		
Interest expense, net	**50,899**	46,977
Distributions on preferred securities of subsidiaries	**14,776**	14,776
Total interest charges and other, net	**65,675**	61,753
Earnings Before Income Taxes	**176,918**	156,669
Income taxes	**69,333**	62,800
Net Income Before Cumulative Effect of Accounting Change	**107,585**	93,869
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $162 thousand	**257**	-
Net Income	**107,842**	93,869
Dividends on Preferred Stock	**168**	170
Net Income After Dividends on Preferred Stock	**$ 107,674**	$ 93,699

The accompanying notes as they relate to GEORGIA are an integral part of these condensed statements.

GEORGIA POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Operating Activities:		
Net income	**$107,842**	$93,869
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization	**169,340**	201,886
Deferred income taxes and investment tax credits, net	**(45,751)**	(11,679)
Other, net	**4,206**	(7,996)
Changes in certain current assets and liabilities --		
Receivables, net	**122,153**	48,673
Fossil fuel stock	**(69,881)**	7,412
Materials and supplies	**(2,975)**	(1,361)
Accounts payable	**(117,678)**	(65,168)
Energy cost recovery, retail	**38,874**	(9,930)
Other	**70,846**	(3,060)
Net cash provided from operating activities	**276,976**	252,646
Investing Activities:		
Gross property additions	**(385,544)**	(212,360)
Other	**(24,444)**	(74,899)
Net cash used for investing activities	**(409,988)**	(287,259)
Financing Activities:		
Increase (decrease) in notes payable, net	**(170,727)**	(50,097)
Proceeds --		
Other long-term debt	**450,000**	300,000
Capital contributions from parent company	**200,000**	-
Retirements --		
First mortgage bonds	**(200,000)**	(100,000)
Preferred stock	**-**	(279)
Payment of preferred stock dividends	**(83)**	(125)
Payment of common stock dividends	**(134,500)**	(136,500)
Other	**(4,775)**	(43)
Net cash provided from financing activities	**139,915**	12,956
Net Change in Cash and Cash Equivalents	**6,903**	(21,657)
Cash and Cash Equivalents at Beginning of Period	**29,370**	34,660
Cash and Cash Equivalents at End of Period	**$ 36,273**	$ 13,003
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$38,299**	$56,096
Income taxes (net of refunds)	**($13,135)**	$1,604

The accompanying notes as they relate to GEORGIA are an integral part of these condensed statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS

Assets	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 36,273	$ 29,370
Receivables --		
Customer accounts receivable	385,245	465,249
Under recovered retail fuel clause revenue	92,749	131,623
Other accounts and notes receivable	96,714	156,143
Affiliated companies	21,088	13,312
Accumulated provision for uncollectible accounts	(9,250)	(5,100)
Fossil fuel stock, at average cost	169,344	99,463
Materials and supplies, at average cost	266,584	263,609
Other	129,882	97,515
Total current assets	1,188,629	1,251,184
Property, Plant, and Equipment:		
In service	16,555,456	16,469,706
Less accumulated provision for depreciation	6,974,952	6,914,512
	9,580,504	9,555,194
Nuclear fuel, at amortized cost	108,887	120,570
Construction work in progress	917,921	652,264
Total property, plant, and equipment	10,607,312	10,328,028
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	26,440	25,485
Nuclear decommissioning trusts	365,515	375,666
Other	37,786	33,829
Total other property and investments	429,741	434,980
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	560,491	565,982
Prepaid pension costs	220,586	205,113
Debt expense, being amortized	57,582	53,748
Premium on reacquired debt, being amortized	171,242	173,610
Other	114,557	120,964
Total deferred charges and other assets	1,124,458	1,119,417
Total Assets	$13,350,140	$13,133,609

The accompanying notes as they relate to GEORGIA are an integral part of these condensed statements.

GEORGIA POWER COMPANY
CONDENSED BALANCE SHEETS

Liabilities and Stockholder's Equity	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 301,846**	$ 1,808
Notes payable and commercial paper	**533,112**	703,839
Accounts payable --		
Affiliated	**66,967**	117,168
Other	**306,738**	397,550
Customer deposits	**80,134**	78,540
Taxes accrued --		
Income taxes	**133,530**	5,151
Other	**53,983**	137,511
Interest accrued	**72,660**	47,244
Vacation pay accrued	**39,501**	38,865
Other	**152,898**	153,400
Total current liabilities	**1,741,369**	1,681,076
Long-term debt	**2,991,667**	3,041,939
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,167,336**	2,182,783
Deferred credits related to income taxes	**242,520**	247,067
Accumulated deferred investment tax credits	**348,582**	352,282
Employee benefits provisions	**182,287**	177,444
Other	**449,050**	397,655
Total deferred credits and other liabilities	**3,389,775**	3,357,231
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes	**789,250**	789,250
Preferred stock	**14,569**	14,569
Common Stockholder's Equity		
Common stock, without par value--		
Authorized - 15,000,000 shares		
Outstanding - 7,761,500 shares	**344,250**	344,250
Paid-in capital	**2,317,497**	2,117,497
Premium on preferred stock	**40**	40
Retained earnings	**1,760,931**	1,787,757
Accumulated other comprehensive income	**792**	-
Total common stockholder's equity	**4,423,510**	4,249,544
Total Liabilities and Stockholder's Equity	**$13,350,140**	$13,133,609

The accompanying notes as they relate to GEORGIA are an integral part of these condensed statements.

GEORGIA POWER COMPANY

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Net Income After Dividends on Preferred Stock	**$107,674**	$93,699
Other comprehensive income:		
Cumulative effect of accounting change	**466**	-
Current period changes in fair value	**825**	-
Related income tax benefits	**(499)**	-
COMPREHENSIVE INCOME	**$108,466**	$93,699

GEORGIA POWER COMPANY

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (UNAUDITED)

	At March 31, 2001	At December 31, 2000
	(in thousands)	
Balance at beginning of period	**$ -**	$ -
Change in current period	**792**	-
BALANCE AT END OF PERIOD	**$ 792**	$ -

The accompanying notes as they relate to GEORGIA are an integral part of these condensed statements.

GEORGIA POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Earnings

GEORGIA's net income after dividends on preferred stock for the first quarter 2001 was $107.7 million compared to $93.7 million for the corresponding period in 2000. Earnings increased $14 million or 14.9% primarily due to increased operating revenues which were partially offset by increased operating expenses.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease)	
	First Quarter	
	(in thousands)	%
Retail sales	$40,117	4.4
Sales for resale - non-affiliates	43,902	100.5
Sales for resale - affiliates	23,844	199.8
Other revenues	8,527	31.6
Fuel expense	17,785	8.4
Purchased power - non-affiliates	10,995	25.5
Purchased power - affiliates	31,555	66.1
Other operation expense	16,591	10.4
Maintenance expense	8,532	8.7

Retail sales. Excluding fuel revenues, which generally do not affect net income, retail sales revenue in the first quarter of 2001 was higher compared to the same period in 2000 due primarily to increased energy sales to residential and commercial customers. Residential and commercial energy sales were up by 7.7% and 7.6%, respectively, due mainly to growth in the number of customers and weather.

Sales for resale - non-affiliates. In the first quarter of 2001, these revenues increased compared to the same period in 2000 as a result of the higher demand for energy by non-affiliates. These transactions do not have a significant impact on earnings since the energy is usually sold at variable cost. These revenues also reflect sales from Plant Dahlberg which went into service in the second quarter of 2000.

Sales for resale - affiliates and Purchased power - affiliates. Revenues from sales for resale to affiliated companies, as well as purchases of energy, within the SOUTHERN system will vary from period to period 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 revenues. These revenues increased in the current quarter of 2001 when compared to the same period in 2000 due principally to higher revenues from transmission of electricity for others and pole attachment rentals.

Fuel expense. These expenses increased in the first quarter of 2001 when compared to the same period in 2000 due primarily to increased generation from fossil-fueled plants to meet higher energy demands. Since energy expenses are generally offset by energy revenues, these expenses do not have a significant impact on earnings.

Purchased power - non-affiliates. For the first quarter of 2001, power purchased from non-affiliates increased when compared to the same period in 2000 due primarily to increased demand for energy as well as the effect of the drought in GEORGIA's service area on hydro generation and increased prices for natural gas and oil. These expenses do not have a significant impact on earnings since energy expenses are generally offset by energy revenues.

Other operation expense. Other operation expense increased during the first quarter of 2001 when compared to the corresponding period in 2000 as a result of higher costs associated with uncollectible accounts and injuries and damages expenses.

Maintenance expense. The increase in this expense for the first quarter of 2001 when compared to the same period in 2000 is primarily attributed to scheduled work performed at steam generating facilities and at transmission and distribution facilities.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors including weather, regulatory matters and energy sales.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, GEORGIA is positioning the business to meet the challenge of increasing competition. For additional information, see Item 1 - BUSINESS - "Competition" and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of GEORGIA in the Form 10-K.

GEORGIA will file a general rate case on July 2, 2001, in response to which the Georgia PSC is expected to determine whether the current three-year rate order should be continued, modified or discontinued when it ends on December 31, 2001. Under the order, GEORGIA's earnings are evaluated against a retail return on common equity range of 10% to 12.5%. Reference is made to Note (H) in the "Notes to the Condensed Financial Statements" herein and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of GEORGIA in the Form 10-K for additional information.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

On April 12, 2001, GEORGIA filed a fuel cost recovery case with the Georgia PSC to increase the retail fuel rate. The purpose of the filing is to review the current fuel price and consider adjusting that price to be more reflective of current fuel market conditions and to collect the under recovery of prior costs. Georgia state law allows GEORGIA to recover all fuel costs. As of March 31, 2001, GEORGIA was under recovered by $92.7 million. The Georgia PSC is expected to decide the case on May 24, 2001.

Compliance costs related to the Clean Air Act and other environmental issues could affect earnings. For additional information, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Issues" of GEORGIA in the Form 10-K.

Reference is made to Notes (C) through (I) and (L) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential.

Adoption of New Accounting Standard

Effective January 1, 2001, GEORGIA adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

The major change in GEORGIA's financial condition during the first three months of 2001 was the addition of approximately $385.5 million to utility plant. The funds for these additions and other capital requirements were derived primarily from operations and capital contributions from SOUTHERN. See GEORGIA's Condensed Statements of Cash Flows for further details.

Financing Activities

In February 2001, GEORGIA issued $350 million aggregate principal amount of senior notes consisting of $200 million of Series F 5.75% Senior Notes due January 31, 2003 and $150 million Series G 6.20% Senior Notes due February 1, 2006. The proceeds of the sale were applied to redeem $200 million of 6 5/8% Series First Mortgage Bonds due April 2003 and to repay a portion of GEORGIA's outstanding short-term indebtedness. Also in February 2001, GEORGIA issued $100 million of Series H 6.70% Senior Insured Quarterly Notes due March 1, 2011. The proceeds of this sale were used to repay an additional portion of GEORGIA's outstanding short-term indebtedness. In May 2001, GEORGIA issued $90 million of Series I 5.25% Senior Notes due May 8, 2003. The proceeds of this sale will be used to redeem in June 2001 the $75 million outstanding principal amount of GEORGIA's 6.35% Series, First Mortgage Bonds due August 1, 2003 and to repay a portion of GEORGIA's outstanding short-term indebtedness.

Capital Requirements

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS of GEORGIA under "Liquidity and Capital Requirements" and "Environmental Issues" in the Form 10-K for a description of GEORGIA's capital requirements for its construction program and environmental compliance efforts.

Sources of Capital

In addition to the financing activities previously described herein, GEORGIA plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon maintenance of adequate earnings, regulatory approval, prevailing market conditions and other factors. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, GEORGIA had at March 31, 2001 approximately $36.3 million of cash and cash equivalents and approximately $1.765 billion of unused credit arrangements with banks. The credit arrangements provide liquidity support to GEORGIA's obligations with respect to variable rate pollution control bonds and its commercial paper program. GEORGIA may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of GEORGIA. At March 31, 2001, GEORGIA had outstanding $533.1 million of commercial paper. Management believes that the need for working capital can be adequately met by utilizing lines of credit without maintaining large cash balances.

GULF POWER COMPANY

GULF POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	For the Three Months Ended March 31, 2000
	(in thousands)	
Operating Revenues:		
Retail sales	$125,563	$116,807
Sales for resale --		
Non-affiliates	20,147	10,978
Affiliates	8,610	8,667
Other revenues	10,709	2,046
Total operating revenues	165,029	138,498
Operating Expenses:		
Operation --		
Fuel	49,332	41,643
Purchased power --		
Non-affiliates	8,501	6,614
Affiliates	11,566	3,158
Other	27,226	27,188
Maintenance	13,459	14,176
Depreciation and amortization	16,675	16,367
Taxes other than income taxes	13,485	13,345
Total operating expenses	140,244	122,491
Operating Income	24,785	16,007
Other Income (Expense):		
Interest income	170	438
Other, net	(799)	(504)
Earnings Before Interest and Income Taxes	24,156	15,941
Interest and Other:		
Interest expenses, net	6,273	7,068
Distributions on preferred securities of subsidiary	1,550	1,550
Total interest charges and other, net	7,823	8,618
Earnings Before Income Taxes	16,333	7,323
Income taxes	6,151	2,616
Net Income Before Cumulative Effect of Accounting Change	10,182	4,707
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $42 thousand	68	-
Net Income	10,250	4,707
Dividends on Preferred Stock	54	54
Net Income After Dividends on Preferred Stock	$ 10,196	$ 4,653

The accompanying notes as they relate to GULF are an integral part of these condensed statements.

GULF POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Activities:		
Net income	**$10,250**	$ 4,707
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization	**17,636**	17,342
Deferred income taxes and investment tax credits, net	**(269)**	(3,587)
Other, net	**87**	(725)
Changes in certain current assets and liabilities --		
Receivables, net	**26,708**	10,856
Fossil fuel stock	**(18,587)**	(5,319)
Materials and supplies	**(225)**	925
Accounts payable	**(18,470)**	(782)
Other	**(1,222)**	7,185
Net cash provided from operating activities	**15,908**	30,602
Investing Activities:		
Gross property additions	**(46,419)**	(18,605)
Other	**(5,281)**	(8,795)
Net cash used for investing activities	**(51,700)**	(27,400)
Financing Activities:		
Increase (decrease) in notes payable, net	**(23,000)**	(2,500)
Proceeds --		
Capital contributions from parent company	**70,000**	-
Retirements --		
Other long-term debt	**(71)**	(20)
Payment of preferred stock dividends	**(54)**	(54)
Payment of common stock dividends	**(13,500)**	(14,600)
Other	**-**	(22)
Net cash provided from (used for) financing activities	**33,375**	(17,196)
Net Change in Cash and Cash Equivalents	**(2,417)**	(13,994)
Cash and Cash Equivalents at Beginning of Period	**4,381**	15,753
Cash and Cash Equivalents at End of Period	**$ 1,964**	$ 1,759
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$7,041**	$9,762
Income taxes (net of refunds)	**2,499**	-

The accompanying notes as they relate to GULF are an integral part of these condensed statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS

Assets	**At March 31, 2001 (Unaudited)**	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 1,964	$ 4,381
Receivables --		
Customer accounts receivable	50,674	69,820
Other accounts and notes receivable	4,428	2,179
Affiliated companies	5,009	15,026
Accumulated provision for uncollectible accounts	(1,096)	(1,302)
Fossil fuel stock, at average cost	35,355	16,768
Materials and supplies, at average cost	29,258	29,033
Regulatory clauses under recovery	4,074	2,112
Other	7,845	6,543
Total current assets	137,511	144,560
Property, Plant, and Equipment:		
In service	1,908,323	1,892,023
Less accumulated provision for depreciation	879,725	867,260
	1,028,598	1,024,763
Construction work in progress	97,161	71,008
Total property, plant, and equipment	1,125,759	1,095,771
Other Property and Investments	6,589	4,510
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	16,208	15,963
Prepaid pension costs	24,923	23,491
Debt expense, being amortized	2,353	2,392
Premium on reacquired debt, being amortized	15,498	15,866
Other	15,405	12,943
Total deferred charges and other assets	74,387	70,655
Total Assets	$1,344,246	$1,315,496

The accompanying notes as they relate to GULF are an integral part of these condensed statements.

GULF POWER COMPANY
CONDENSED BALANCE SHEETS

Liabilities and Stockholder's Equity	**At March 31, 2001 (Unaudited)**	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Notes payable	**$ 20,000**	$ 43,000
Accounts payable --		
Affiliated	**14,736**	17,558
Other	**24,610**	38,153
Customer deposits	**13,678**	13,474
Taxes accrued --		
Income taxes	**7,536**	3,864
Other	**7,137**	8,749
Interest accrued	**8,720**	8,324
Provision for rate refund	**2,697**	7,203
Vacation pay accrued	**4,512**	4,512
Regulatory clauses over recovery	**5,574**	6,848
Other	**2,535**	1,584
Total current liabilities	**111,735**	153,269
Long-term debt	**366,009**	365,993
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**155,999**	155,074
Deferred credits related to income taxes	**37,300**	38,255
Accumulated deferred investment tax credits	**25,312**	25,792
Employee benefits provisions	**35,536**	34,507
Other	**29,045**	25,992
Total deferred credits and other liabilities	**283,192**	279,620
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes	**85,000**	85,000
Preferred stock	**4,236**	4,236
Common Stockholder's Equity		
Common stock, without par value--		
Authorized - 992,717 shares		
Outstanding - 992,717 shares	**38,060**	38,060
Paid-in capital	**303,476**	233,476
Premium on preferred stock	**12**	12
Retained earnings	**152,526**	155,830
Total common stockholder's equity	**494,074**	427,378
Total Liabilities and Stockholder's Equity	**$1,344,246**	**$1,315,496**

The accompanying notes as they relate to GULF are an integral part of these condensed statements.

GULF POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Earnings

GULF's net income after dividends on preferred stock for the first quarter of 2001 was $10.2 million compared to $4.7 million for the same period in 2000. GULF's earnings were up primarily due to higher operating revenues.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease) First Quarter (in thousands)	%
Retail sales	$8,756	7.5
Sales for resale - non-affiliates	9,169	83.5
Other revenues	8,663	N/M
Fuel expense	7,689	18.5
Purchased power - non-affiliates	1,887	28.5
Purchased power - affiliates	8,408	266.2

N/M - Not meaningful

Retail sales. Excluding the recovery of fuel expense and certain other expenses that do not affect net income, retail sales increased $6.5 million or 9.3% during the first quarter of 2001 when compared to the same period of 2000. The increase in retail sales revenue is related to increases in energy sales of 13.6%, 4.9% and 10.1% to residential, commercial and industrial customers, respectively. The primary reasons for the energy sales increase are colder weather in January, warmer weather in March, and growth in the number of customers served by GULF.

Sales for resale - non-affiliates. During the first quarter of 2001, these revenues increased when compared to the same period in 2000 due primarily to increased unit power energy sales. These transactions do not have a significant impact on earnings since the energy is usually sold at variable cost.

Other revenues. The increase for the first quarter of 2001 is primarily related to fuel clause adjustments made to other operating revenues to reflect the difference between recoverable costs and the amounts actually reflected in current rates. The recovery provisions generally equal the related expenses and have no material effect on net income.

Fuel expense. For the first quarter of 2001, fuel expenses increased when compared to the same period in 2000 due mainly to increased generation to meet higher energy demand. Since energy expenses are generally offset by energy revenues, these expenses do not have a significant impact on net income.

Purchased power - non-affiliates. The increase for the first quarter of 2001 when compared to the same period in 2000 is primarily attributed to an increase in capacity and energy purchases to meet the demand for energy. Since energy expenses are generally offset by energy revenues, these expenses do not have a significant impact on net income.

Purchased power - affiliates. Purchases of energy from affiliates within the SOUTHERN system will vary from period to period depending on demand and the availability and cost of generating resources at each company. These transactions do not have a significant impact on earnings.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from weather to energy sales growth to a less regulated, more competitive environment.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, GULF is positioning the business to meet the challenge of increasing competition. For additional information, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of GULF and Item 1 - BUSINESS - "Competition" in the Form 10-K.

Compliance costs related to the Clean Air Act could affect earnings if such costs are not fully recovered through GULF's Environmental Cost Recovery Clause. For additional information about the Clean Air Act and other environmental issues, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" of GULF in the Form 10-K.

In 1999, the Florida PSC approved GULF's plan to reduce its authorized rate of return, reduce retail base rates and share revenues with its customers. For additional information, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of GULF in the Form 10-K.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

Reference is also made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" and Note 3 to the financial statements of GULF in the Form 10-K for information on EPA litigation.

Reference is made to Notes (C) through (E) and (G) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential.

Adoption of New Accounting Standard

Effective January 1, 2001, GULF adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

Major changes in GULF's financial condition during the first three months of 2001 included the addition of approximately $46.4 million to utility plant. The funds for these additions and other capital requirements were derived primarily from operations and capital contributions from SOUTHERN. See GULF's Condensed Statements of Cash Flows for further details.

Financing Activities

GULF plans to continue, to the extent possible, a program to retire higher-cost debt and replace these securities with lower-cost capital.

Capital Requirements

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS of GULF under "Capital Requirements for Construction" and "Environmental Matters" in the Form 10-K for a description of GULF's capital requirements for its construction program, environmental compliance efforts and maturing debt.

Sources of Capital

In addition to the financing activities previously described herein, GULF plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon maintenance of adequate earnings, regulatory approval, prevailing market conditions and other factors. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, GULF had at March 31, 2001 approximately $2.0 million of cash and cash equivalents and $52.5 million of unused committed lines of credit with banks in addition to $61.9 million of liquidity support for GULF's obligations with respect to variable rate pollution control bonds. GULF may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of GULF. At March 31, 2001, GULF had short-term notes payable outstanding of $20 million. Management believes that the need for working capital can be adequately met by utilizing lines of credit without maintaining large cash balances.

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MISSISSIPPI POWER COMPANY

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Revenues:		
Retail sales	**$114,579**	$100,962
Sales for resale --		
Non-affiliates	**40,288**	26,562
Affiliates	**11,988**	4,581
Other revenues	**4,457**	2,600
Total operating revenues	**171,312**	134,705
Operating Expenses:		
Operation --		
Fuel	**37,484**	37,060
Purchased power --		
Non-affiliates	**14,623**	4,008
Affiliates	**31,536**	11,622
Other	**26,369**	26,731
Maintenance	**13,848**	12,937
Depreciation and amortization	**11,916**	11,713
Taxes other than income taxes	**11,921**	12,041
Total operating expenses	**147,697**	116,112
Operating Income	**23,615**	18,593
Other Income:		
Interest income	**144**	99
Other, net	**207**	354
Earnings Before Interest and Income Taxes	**23,966**	19,046
Interest Expense and Other:		
Interest expense, net	**6,946**	6,954
Distributions on preferred securities of subsidiary	**678**	699
Total interest charges and other, net	**7,624**	7,653
Earnings Before Income Taxes	**16,342**	11,393
Income taxes	**6,124**	4,168
Net Income Before Cumulative Effect of Accounting Change	**10,218**	7,225
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $43 thousand	**70**	-
Net Income	**10,288**	7,225
Dividends on Preferred Stock	**531**	503
Net Income After Dividends on Preferred Stock	**$ 9,757**	$ 6,722

The accompanying notes as they relate to MISSISSIPPI are an integral part of these condensed statements.

MISSISSIPPI POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Activities:		
Net income	**$10,288**	$ 7,225
Adjustments to reconcile net income to net cash provided from operating activities --		
Depreciation and amortization	**12,892**	12,826
Deferred income taxes and investment tax credits, net	**(1,443)**	(7,811)
Other, net	**(5,331)**	(1,402)
Changes in certain current assets and liabilities --		
Receivables, net	**6,568**	18,649
Fossil fuel stock	**(13,020)**	3,999
Materials and supplies	**133**	(371)
Accounts payable	**(1,545)**	(4,542)
Other	**(15,268)**	(11,490)
Net cash provided from (used for) operating activities	**(6,726)**	17,083
Investing Activities:		
Gross property additions	**(14,151)**	(16,372)
Other	**(3,972)**	(5,881)
Net cash used for investing activities	**(18,123)**	(22,253)
Financing Activities:		
Increase (decrease) in notes payable, net	**34,200**	(30,500)
Proceeds --		
Other long-term debt	**-**	100,000
Retirements --		
Other long-term debt	**(379)**	(50,208)
Payment of preferred stock dividends	**(531)**	(503)
Payment of common stock dividends	**(12,800)**	(13,600)
Net cash provided from financing activities	**20,490**	5,189
Net Change in Cash and Cash Equivalents	**(4,359)**	19
Cash and Cash Equivalents at Beginning of Period	**7,531**	173
Cash and Cash Equivalents at End of Period	**$ 3,172**	$ 192
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$5,785**	$5,882
Income taxes (net of refunds)	**$1,472**	$73

The accompanying notes as they relate to MISSISSIPPI are an integral part of these condensed statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS

Assets	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 3,172	$ 7,531
Receivables --		
Customer accounts receivable	40,823	48,001
Under recovered regulatory clauses	23,687	24,063
Other accounts and notes receivable	17,364	21,843
Affiliated companies	15,591	10,071
Accumulated provision for uncollectible accounts	(626)	(571)
Fossil fuel stock, at average cost	24,240	11,220
Materials and supplies, at average cost	21,561	21,694
Other	12,702	8,320
Total current assets	158,514	152,172
Property, Plant, and Equipment:		
In service	1,673,232	1,665,879
Less accumulated provision for depreciation	662,174	652,891
	1,011,058	1,012,988
Construction work in progress	64,131	60,951
Total property, plant, and equipment	1,075,189	1,073,939
Other Property and Investments	2,500	2,268
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	13,764	13,860
Prepaid pension costs	7,651	6,724
Debt expense, being amortized	4,573	4,628
Premium on reacquired debt, being amortized	7,006	7,168
Other	22,007	14,312
Total deferred charges and other assets	55,001	46,692
Total Assets	$1,291,204	$1,275,071

The accompanying notes as they relate to MISSISSIPPI are an integral part of these condensed statements.

MISSISSIPPI POWER COMPANY
CONDENSED BALANCE SHEETS

Liabilities and Stockholders' Equity	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 100,020	$ 20
Notes payable	90,200	56,000
Accounts payable --		
Affiliated	5,222	10,715
Other	49,654	48,146
Customer deposits	5,572	5,274
Taxes accrued --		
Income taxes	16,543	8,769
Other	14,257	36,799
Interest accrued	6,025	4,482
Vacation pay accrued	5,701	5,701
Other	8,198	7,003
Total current liabilities	301,392	182,909
Long-term debt	270,161	370,511
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	139,882	139,909
Deferred credits related to income taxes	24,937	25,603
Accumulated deferred investment tax credits	23,178	23,481
Employee benefits provisions	35,093	34,671
Workforce reduction plan	9,359	9,734
Other	18,538	16,546
Total deferred credits and other liabilities	250,987	249,944
Company obligated mandatorily redeemable preferred securities of subsidiary trust holding company junior subordinated notes	35,000	35,000
Preferred stock	31,809	31,809
Common Stockholder's Equity		
Common stock equity --		
Authorized - 1,130,000 shares		
Outstanding - 1,121,000 shares		
Par value	37,691	37,691
Paid-in capital	194,160	194,161
Premium on preferred stock	326	326
Retained earnings	169,678	172,720
Total common stockholder's equity	401,855	404,898
Total Liabilities and Stockholder's Equity	$1,291,204	$1,275,071

The accompanying notes as they relate to MISSISSIPPI are an integral part of these condensed statements.

MISSISSIPPI POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Earnings

MISSISSIPPI's net income after dividends on preferred stock for the first quarter of 2001 was $9.8 million, compared to $6.7 million for the corresponding period of 2000. Earnings increased in the first quarter of 2001 when compared to the same period in 2000 due primarily to higher operating revenues.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease)	
	First Quarter	
	(in thousands)	%
Retail sales	$13,617	13.5
Sales for resale - non-affiliates	13,726	51.7
Sales for resale - affiliates	7,407	161.7
Other revenues	1,857	71.4
Purchased power - non-affiliates	10,615	264.8
Purchased power - affiliates	19,914	171.3

Retail sales. Excluding fuel revenues, which generally do not affect net income, retail sales revenue was up by $0.9 million or 1.4% during the current quarter of 2001 when compared to the corresponding period in 2000 due primarily to increased energy sales to residential customers. Energy sales to residential customers during the first quarter of 2001 increased due mainly to weather.

Sales for resale - non-affiliates. The increase in sales for resale to non-affiliates during the first quarter of 2001, as compared to the same period in 2000, is primarily due to increased demand for energy from these non-affiliated companies.

Sales for resale - affiliates and Purchased power - affiliates. Revenues from sales for resale to affiliated companies, as well as purchases of energy, within the SOUTHERN system will vary from period to period depending on demand and the availability and cost of generating resources at each company. These transactions do not have a significant impact on earnings.

Other revenues. These revenues increased in the first quarter of 2001 when compared to the same period in 2000 primarily as a result of sales of inventory.

Purchased power - non-affiliates. In the first quarter of 2001, purchased power from non-affiliates was higher when compared to the same period in 2000 due mainly to the need to meet the higher demand for energy. These transactions do not have a significant impact on net income since energy expenses are generally offset by energy revenues.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from weather to energy sales growth to a less regulated, more competitive environment. Operating revenues will be affected by any changes in rates under the PEP and ECO plans. The PEP has proven to be a stabilizing force on electric rates, with only moderate changes in rates taking place. For additional information, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of MISSISSIPPI in the Form 10-K.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, MISSISSIPPI is positioning the business to meet the challenge of increasing competition. For additional information, see Item 1 - BUSINESS - "Competition" and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of MISSISSIPPI in the Form 10-K.

Compliance costs related to the Clean Air Act could affect earnings if such costs cannot be recovered. MISSISSIPPI's 2001 ECO Plan filing was approved, as filed, by the Mississippi PSC on March 7, 2001 and resulted in a slight increase in customer prices. For additional information about the Clean Air Act and other environmental issues, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" of MISSISSIPPI in the Form 10-K.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

Reference is also made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" and Note 3 to the financial statements of MISSISSIPPI in the Form 10-K for information on EPA litigation.

Reference is made to Notes (C) through (E), (G) and (M) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential.

Adoption of New Accounting Standard

Effective January 1, 2001, MISSISSIPPI adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

Major changes in MISSISSIPPI's financial condition during the first three months of 2001 included the addition of approximately $14.2 million to utility plant. The funds for these additions and other capital requirements were derived primarily from operations and financing activities. See MISSISSIPPI's Condensed Statements of Cash Flows for further details.

Financing Activities

Reference is made to Item 7 – MANAGEMENT'S DISCUSSION AND ANALYSIS – "Financing Activity" and Note 4 to the financial statements of MISSISSIPPI in the Form 10-K. Effective May 4, 2001, in connection with commercial operation of a 1,064-megawatt natural gas combined cycle facility, MISSISSIPPI entered into the initial 10-year lease term with Escatawpa Funding, Limited Partnership. The final completion cost will be approximately $370 million. Reference is made to Note (M) in the "Notes to the Condensed Financial Statements" herein for additional information.

MISSISSIPPI plans to continue, to the extent possible, a program to retire higher-cost debt and replace these securities with lower-cost capital.

Capital Requirements

Reference is made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS of MISSISSIPPI under "Capital Requirements for Construction," "Environmental Matters" and "Other Capital Requirements" and Note 3 to the financial statements in the Form 10-K for a description of MISSISSIPPI's capital requirements for its construction program, environmental compliance efforts, sinking fund requirements and maturities of long-term debt.

Sources of Capital

In addition to the financing activities previously described herein, MISSISSIPPI plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon maintenance of adequate earnings, regulatory approval, prevailing market conditions and other factors. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, MISSISSIPPI had at March 31, 2001 approximately $3.2 million of cash and cash equivalents and approximately $124.3 million of unused committed credit arrangements with banks. MISSISSIPPI may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of MISSISSIPPI. At March 31, 2001, MISSISSIPPI had short-term notes payable outstanding of $90.2 million. Management believes that the need for working capital can be adequately met by utilizing lines of credit without maintaining large cash balances.

SAVANNAH ELECTRIC
AND
POWER COMPANY

SAVANNAH ELECTRIC AND POWER COMPANY
CONDENSED STATEMENTS OF INCOME (UNAUDITED)

	For the Three Months Ended March 31, 2001	2000
	(in thousands)	
Operating Revenues:		
Retail sales	**$58,419**	$49,785
Sales for resale --		
Non-affiliates	**1,558**	569
Affiliates	**1,227**	1,721
Other revenues	**487**	315
Total operating revenues	**61,691**	52,390
Operating Expenses:		
Operation --		
Fuel	**9,394**	9,747
Purchased power --		
Non-affiliates	**2,326**	2,188
Affiliates	**15,748**	8,050
Other	**12,116**	12,047
Maintenance	**6,048**	4,666
Depreciation and amortization	**6,460**	6,309
Taxes other than income taxes	**3,235**	3,044
Total operating expenses	**55,327**	46,051
Operating Income	**6,364**	6,339
Other Income (Expense):		
Interest income	**33**	41
Other, net	**(176)**	(142)
Earnings Before Interest and Income Taxes	**6,221**	6,238
Interest Charges and Other:		
Interest expense, net	**3,276**	3,021
Distributions on preferred securities of subsidiary	**685**	685
Total interest charges and other, net	**3,961**	3,706
Earnings Before Income Taxes	**2,260**	2,532
Income taxes	**806**	889
Net Income Before Cumulative Effect of Accounting Change	**1,454**	1,643
Cumulative effect as of January 1, 2001 of accounting change -- less income taxes of $14 thousand	**22**	-
Net Income	**$ 1,476**	$ 1,643

The accompanying notes as they relate to SAVANNAH are an integral part of these condensed statements.

SAVANNAH ELECTRIC AND POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS (UNAUDITED)

	For the Three Months Ended March 31,	
	2001	2000
	(in thousands)	
Operating Activities:		
Net income	**$1,476**	$1,643
Adjustments to reconcile net income		
to net cash provided from operating activities --		
Depreciation and amortization	**6,999**	6,777
Deferred income taxes and investment tax credits, net	**(699)**	(1,342)
Other, net	**2,140**	1,563
Changes in certain current assets and liabilities --		
Receivables, net	**4,530**	2,753
Fossil fuel stock	**(1,143)**	955
Materials and supplies	**(206)**	(588)
Accounts payable	**(9,931)**	2,364
Other	**2,054**	(731)
Net cash provided from operating activities	**5,220**	13,394
Investing Activities:		
Gross property additions	**(11,068)**	(7,049)
Other, net	**1,467**	(2,683)
Net cash used for investing activities	**(9,601)**	(9,732)
Financing Activities:		
Increase (decrease) in notes payable, net	**14,415**	(400)
Retirements --		
Other long-term debt	**(254)**	(182)
Payment of common stock dividends	**(5,500)**	(6,100)
Net cash provided from (used for) financing activities	**8,661**	(6,682)
Net Change in Cash and Cash Equivalents	**4,280**	(3,020)
Cash and Cash Equivalents at Beginning of Period	**-**	6,553
Cash and Cash Equivalents at End of Period	**$4,280**	$3,533
Supplemental Cash Flow Information:		
Cash paid during the period for --		
Interest (net of amount capitalized)	**$3,532**	$2,170
Income taxes (net of refunds)	**(3,459)**	920

The accompanying notes as they relate to SAVANNAH are an integral part of these condensed statements.

SAVANNAH ELECTRIC AND POWER COMPANY
CONDENSED BALANCE SHEETS

Assets	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 4,280	$ -
Receivables --		
Customer accounts receivable	24,129	28,189
Under recovered retail fuel clause revenue	39,452	39,632
Other accounts and notes receivable	1,120	1,412
Affiliated companies	693	738
Accumulated provision for uncollectible accounts	(360)	(407)
Fossil fuel stock, at average cost	8,283	7,140
Materials and supplies, at average cost	9,150	8,944
Prepaid Taxes	3,673	8,651
Other	1,363	377
Total current assets	91,783	94,676
Property, Plant, and Equipment:		
In service	834,787	829,270
Less accumulated provision for depreciation	387,901	382,030
	446,886	447,240
Construction work in progress	12,000	6,782
Total property, plant, and equipment	458,886	454,022
Other Property and Investments	2,110	2,066
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	12,735	12,404
Cash surrender value of life insurance for deferred compensation plans	17,632	17,954
Debt expense, being amortized	2,963	3,003
Premium on reacquired debt, being amortized	7,373	7,575
Other	2,610	2,527
Total deferred charges and other assets	43,313	43,463
Total Assets	$596,092	$594,227

The accompanying notes as they relate to SAVANNAH are an integral part of these condensed statements.

SAVANNAH ELECTRIC AND POWER COMPANY
CONDENSED BALANCE SHEETS

Liabilities and Stockholder's Equity	At March 31, 2001 (Unaudited)	At December 31, 2000
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 31,285	$ 30,698
Notes payable	59,815	45,400
Accounts payable --		
Affiliated	6,813	16,153
Other	8,746	7,738
Customer deposits	5,867	5,696
Taxes accrued --		
Income taxes	3,184	3,450
Other	2,566	1,435
Interest accrued	4,725	4,541
Vacation pay accrued	2,298	2,276
Other	4,342	7,973
Total current liabilities	129,641	125,360
Long-term debt	116,061	116,902
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	79,455	79,756
Deferred credits related to income taxes	15,660	16,038
Accumulated deferred investment tax credits	10,450	10,616
Deferred compensation plans	12,715	11,968
Employee benefits provisions	10,435	9,236
Other	10,704	9,357
Total deferred credits and other liabilities	139,419	136,971
Company obligated mandatorily redeemable preferred securities of subsidiary trusts holding company junior subordinated notes	40,000	40,000
Common Stockholder's Equity		
Common stock, par value $5 per share --		
Authorized - 16,000,000 shares		
Outstanding - 10,844,635 shares		
Par value	54,223	54,223
Paid-in capital	11,267	11,265
Retained earnings	105,481	109,506
Total common stockholder's equity	170,971	174,994
Total Liabilities and Stockholder's Equity	$596,092	$594,227

The accompanying notes as they relate to SAVANNAH are an integral part of these condensed statements.

SAVANNAH ELECTRIC AND POWER COMPANY
MANAGEMENT'S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION

FIRST QUARTER 2001 vs. FIRST QUARTER 2000

RESULTS OF OPERATIONS

Earnings

SAVANNAH's net income for the first quarter of 2001 was $1.5 million as compared to $1.6 million for the corresponding period of 2000. Earnings were down slightly due primarily to higher operating expenses which fully offset higher operating revenues.

Significant income statement items appropriate for discussion include the following:

	Increase (Decrease)	
	First Quarter	
	(in thousands)	%
Retail sales	$8,634	17.3
Sales for resale - non-affiliates	989	173.8
Sales for resale - affiliates	(494)	(28.7)
Purchased power - affiliates	7,698	95.6
Maintenance expense	1,382	29.6

Retail sales. Excluding fuel revenues, which do not affect net income, retail sales revenue increased by $1.4 million for the first quarter of 2001 when compared to the same period in 2000 due mainly to an increase in total retail energy sales of 7.4%. Total retail energy sales increased as a result of weather and growth in the number of customers served by SAVANNAH.

Sales for resale - non-affiliates. During the first quarter of 2001, sales for resale to non-affiliates increased due to higher demand for energy by these non-affiliates when compared to the corresponding period in 2000. These transactions do not have a significant impact on earnings since the energy is usually sold at variable cost.

Sales for resale - affiliates and Purchased power - affiliates. Revenues from sales for resale to affiliated companies, as well as purchases of energy, within the SOUTHERN system will vary from period to period depending on demand and the availability and cost of generating resources at each company. These transactions do not have a significant impact on earnings.

Maintenance expense. During the first quarter of 2001, maintenance expenses were higher when compared to the corresponding period in 2000 due primarily to a scheduled major maintenance outage at one of SAVANNAH's plants.

Future Earnings Potential

The results of operations discussed above are not necessarily indicative of future earnings potential. The level of future earnings depends on numerous factors ranging from weather to energy sales growth to a less regulated, more competitive environment.

With the enactment of the Energy Act and new legislation being discussed at federal and state levels to expand customer choice, SAVANNAH is positioning the business to meet the challenge of increasing competition. For additional information, see Item 1 - BUSINESS - "Competition" and Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of SAVANNAH in the Form 10-K.

Compliance costs related to the Clean Air Act could affect earnings if such costs cannot be offset. For additional information about the Clean Air Act and other environmental issues, see Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" of SAVANNAH in the Form 10-K.

On March 14, 2001, the FERC rejected certain elements of SOUTHERN's RTO proposal. For additional information on the FERC's response to SOUTHERN's proposal, reference is made to Item 1 - BUSINESS - "Integrated Southeast Utilities" in the Form 10-K.

Reference is also made to Item 7 - MANAGEMENT'S DISCUSSION AND ANALYSIS - "Environmental Matters" and Note 3 to the financial statements of SAVANNAH in the Form 10-K for information on EPA litigation.

Reference is made to Notes (C) through (E), (G), (L) and (N) in the "Notes to the Condensed Financial Statements" herein for discussion of various contingencies and other matters which may affect future earnings potential.

Adoption of New Accounting Standard

Effective January 1, 2001, SAVANNAH adopted FASB Statement No. 133, as amended, and changed the method of accounting for derivative instruments. All derivatives are now reflected on the Condensed Consolidated Balance Sheet at fair market value. Reference is made to Note (C) in the "Notes to the Condensed Financial Statements" herein for additional information on the adoption of Statement No. 133.

FINANCIAL CONDITION

Overview

Major changes in SAVANNAH's financial condition during the first three months of 2001 included the addition of approximately $11.1 million to utility plant. The funds for these additions and other capital requirements were derived primarily from operations and credit arrangements with banks. See SAVANNAH's Condensed Statements of Cash Flows for further details.

Financing Activities

SAVANNAH plans to continue, to the extent possible, a program to retire higher-cost debt and replace these securities with lower-cost capital.

Sources of Capital

SAVANNAH plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The amount, type and timing of any financings--if needed--will depend upon maintenance of adequate earnings, regulatory approval, prevailing market conditions and other factors. See Item 1 - BUSINESS - "Financing Programs" in the Form 10-K for additional information.

To meet short-term cash needs and contingencies, SAVANNAH had at March 31, 2001 approximately $4.3 million of cash and cash equivalents and approximately $65.5 million of unused committed credit arrangements with banks. SAVANNAH may also meet short-term cash needs through a SOUTHERN subsidiary organized to issue and sell commercial paper at the request and for the benefit of SAVANNAH. At March 31, 2001, SAVANNAH had short-term notes payable outstanding of $59.8 million. Since SAVANNAH has no major generating plants under construction, management believes that the need for working capital can be adequately met by utilizing lines of credit.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS
FOR
THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SAVANNAH ELECTRIC AND POWER COMPANY

INDEX TO APPLICABLE NOTES TO
FINANCIAL STATEMENTS BY REGISTRANT

Registrant	**Applicable Notes**
SOUTHERN	A, B, C, D, E, F, G, H, I, J, K, L, N, O
ALABAMA	A, C, D, E, F, G, L
GEORGIA	A, C, D, E, F, G, H, I, L
GULF	A, C, D, E, G
MISSISSIPPI	A, C, D, E, G, M
SAVANNAH	A, C, D, E, G, L, N

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
ALABAMA POWER COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
MISSISSIPPI POWER COMPANY
SAVANNAH ELECTRIC AND POWER COMPANY

NOTES TO THE CONDENSED FINANCIAL STATEMENTS:

(A) The condensed financial statements of the registrants included herein have been prepared by each registrant, without audit, pursuant to the rules and regulations of the SEC. In the opinion of each registrant's management, the information regarding such registrant furnished herein reflects all adjustments necessary to present fairly the results of operations for the periods ended March 31, 2001 and 2000. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations, although each registrant believes that the disclosures regarding such registrant are adequate to make the information presented not misleading. It is suggested that these condensed financial statements of each registrant be read in conjunction with the financial statements of such registrant and the notes thereto included in the Form 10-K. Certain prior period amounts have been reclassified to conform with current period presentation. Due to seasonal variations in the demand for energy, operating results for the periods presented do not necessarily indicate operating results for the entire year.

(B) Reference is made to Note 11 to the financial statements of SOUTHERN in Item 8 and MANAGEMENT'S DISCUSSION AND ANALYSIS - "Overview of Consolidated Earnings" and "Discontinued Operations" of SOUTHERN in Item 7 of the Form 10-K for information on the spin off of Mirant.

On April 2, 2001, SOUTHERN completed the spin off of Mirant with a tax free distribution to SOUTHERN's shareholders of its remaining ownership of 272 million Mirant shares. Shares from the spin off were distributed at a ratio of approximately 0.4 share of Mirant common stock for every share of SOUTHERN common stock held at the record date.

As a result of the spin off, SOUTHERN's financial statements reflect Mirant as discontinued operations. All historical financial statements presented and footnotes have been reclassified to conform to this presentation, with the historical assets and liabilities of Mirant presented on the Condensed Consolidated Balance Sheet as net assets of discontinued operations.

(C) On January 1, 2001, SOUTHERN and its subsidiaries adopted FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Statement No. 133 requires that certain derivative instruments be recorded in the balance sheet as either an asset or liability measured at fair value and that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

SOUTHERN utilizes financial instruments to reduce its exposure to changes in interest rates and foreign currency exchange rates. Such financial instruments are generally structured so that their terms are substantially identical to (and their changes in market value are highly correlated to) those of SOUTHERN's recorded liabilities or unrecorded firm commitments. Thus, these instruments generally qualify as hedges under Statement No. 133.

The integrated Southeast utilities also enter into commodity related forward and option contracts to limit exposure to changing prices on certain fuel purchases and electricity purchases and sales. Substantially all of the integrated Southeast utilities' bulk energy purchases and sales meet the definition of a derivative under Statement No. 133. In many cases, these transactions meet Statement No. 133's normal purchase and sale exception and the related contracts are accounted for under the accrual method. Certain of these contracts qualify as cash flow hedges of anticipated transactions, resulting in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Certain other contracts do not meet the hedge requirements and are marked to market through current period income.

The cumulative effect of adoption was a reduction of approximately $300 million in comprehensive income, which was all related to discontinued operations. The impact on net income was immaterial and less than $0.01 per share, to each of the integrated Southeast utilities individually, as well as to SOUTHERN on a consolidated basis. The mark to market adjustments recorded during the first quarter of 2001 were also immaterial. However, the application and interpretation of Statement No. 133's requirements is still evolving and further guidance from the FASB is expected, which could further impact the financial statements of SOUTHERN and the integrated Southeast utilities. Also, as wholesale energy markets mature, the accounting for future transactions could be significantly impacted by Statement No. 133, resulting in more volatility in net income and comprehensive income.

Reference is made to MANAGEMENT'S DISCUSSION AND ANALYSIS - "Market Price Risk" of SOUTHERN and the integrated Southeast utilities in Item 7 for each of the registrants in the Form 10-K, and Note 1 to the financial statements of SOUTHERN under the caption "Financial Instruments for Non-Trading Activities" in Item 8 of the Form 10-K.

(D) SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH engage in price risk management activities. Reference is made to MANAGEMENT'S DISCUSSION AND ANALYSIS - "Market Price Risk" in SOUTHERN; and "Exposure to Market Risks," in ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH. Reference is also made to Note 1 to the financial statements of SOUTHERN, ALABAMA and GEORGIA in Item 8 of the Form 10-K for a discussion of these activities.

(E) The integrated Southeast utilities are 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 a company's operations 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. For additional information, see Note 1 to the financial statements of each registrant in Item 8 of the Form 10-K.

(F) The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry--including SOUTHERN's--regarding the recognition, measurement and classification in the financial statements of decommissioning costs for nuclear generating facilities. In response to these questions, the FASB is reviewing the accounting for liabilities related to the retirement of long-lived assets, including nuclear decommissioning. Reference is made to MANAGEMENT'S DISCUSSION AND ANALYSIS - "Future Earnings Potential" of SOUTHERN, ALABAMA and GEORGIA in Item 7 and Note 1 to the financial statements of SOUTHERN, ALABAMA and GEORGIA under "Depreciation and Nuclear Decommissioning" in Item 8 of the Form 10-K.

(G) Reference is made to Note 3 to the financial statements of SOUTHERN, ALABAMA , GEORGIA, GULF, MISSISSIPPI and SAVANNAH in Item 8 of the Form 10-K for information on EPA litigation.

(H) Reference is made to Note 3 to the financial statements of SOUTHERN and GEORGIA in Item 8 of the Form 10-K for information concerning a three-year rate order approved by the Georgia PSC effective January 1, 1999. The order decreased annual retail rates by $262 million effective January 1, 1999 and by an additional $24 million effective January 1, 2000. The order further provides for $85 million each year, plus up to $50 million annually of any earnings above a 12.5% retail return on common equity during the second and third years, to be applied to accelerated amortization or depreciation of assets. In May 2000, the Georgia PSC ordered that these funds be maintained in a regulatory liability account and that interest be accrued on the account at the prime rate. These amounts are reflected on the balance sheets in deferred credits and other liabilities, other. Two-thirds of any additional earnings above the 12.5% return will be applied to rate reductions and the remaining one-third retained by GEORGIA. Pursuant to this provision, GEORGIA recognized accelerated amortization of $37.6 million in the first quarter of 2001 and $36.6 million in the first quarter of 2000.

(I) Reference is made to Note 3 to the financial statements of SOUTHERN and GEORGIA in Item 8 of the Form 10-K for information regarding GEORGIA's designation as a potentially responsible party under the Comprehensive Environmental Response, Compensation and Liability Act and other environmental contingencies.

(J) SOUTHERN has made separate guarantees to certain counterparties regarding performance of contractual commitments by Mirant's trading and marketing subsidiaries. At March 31, 2001, the total notional amount of guarantees was $202.7 million and the estimated fair value of net contractual commitments outstanding was approximately $63 million. Based upon a statistical analysis of credit risk, SOUTHERN's potential exposure under these contractual commitments would not materially differ from the estimated fair value. SOUTHERN also has guaranteed certain of Mirant's foreign currency swap transactions. At March 31, 2001, notional amounts under these swaps were the differences between £22 million and $33.7 million and between DM370 million and $205.6 million; however, due to favorable exchange rates SOUTHERN had no exposure under these guarantees. The sterling and deutsche mark swaps expire in 2002 and 2003, respectively. Subsequent to the spin off, Mirant began paying SOUTHERN a monthly fee of 1 percent on the average aggregate maximum principal amount of all guarantees outstanding until they are replaced or expire. Mirant must use reasonable efforts to release SOUTHERN from all such support arrangements and will indemnify SOUTHERN for any obligations incurred.

Reference is made to Note 9 to the financial statements of SOUTHERN under the caption "Guarantees" in Item 8 of the Form 10-K.

(K) With respect to Mobile Energy, reference is made to Note 3 to the financial statements of SOUTHERN in Item 8 and to Legal Proceedings in Item 3 of the Form 10-K for information relating to (i) petitions for Chapter 11 bankruptcy relief which were filed in the U. S. Bankruptcy Court for the Southern District of Alabama and (ii) proposed settlement discussions among the affected parties.

(L) Reference is made to Note 3 to the financial statements of SOUTHERN in Item 8 and to Legal Proceedings in Item 3 of the Form 10-K for information relating to various lawsuits.

(M) Effective May 4, 2001, in connection with commercial operation of the 1,064-megawatt natural gas combined cycle facility at MISSISSIPPI's Plant Daniel (the "Facility"), MISSISSIPPI entered into the initial 10-year lease term under its lease arrangement for the Facility with Escatawpa Funding, Limited Partnership. The final completion cost will be approximately $370 million. The lease provides for a residual value guarantee (approximately 71% of the acquisition cost) by MISSISSIPPI that is due upon termination of the lease in certain circumstances. The lease also includes purchase and renewal options. Upon termination of the lease, at MISSISSIPPI's option, MISSISSIPPI may either exercise its purchase option or the facility can be sold to a third party. MISSISSIPPI expects the fair market value of the leased facility to substantially reduce or eliminate MISSISSIPPI's payment under the residual value guarantee. The annual amount of future minimum operating lease payments exclusive of any payment related to this guarantee will approximate $30 million during the initial term.

(N) On March 16, 2001, SAVANNAH submitted a filing with the Georgia PSC to establish a new fuel rate in order to better reflect current fuel cost and to collect the under-recovered balance. On April 26, 2001, SAVANNAH received an order from the Georgia PSC allowing SAVANNAH to set the fuel cost recovery rate to recover its approximately $40 million deferred fuel balance over three years, and to recover approximately $137 million in projected annual fuel and purchased power costs, for a total recovery of about $150 million per year. Reflected in the $137 million is a Georgia PSC ordered "cap" of $100 per megawatt on energy strips. Any purchase agreement for summer energy strips priced in excess of the "cap" requires that the amount above $100 per megawatt be "imputed" as capacity and recovered through non-fuel rates. On May 11, 2001, SAVANNAH requested the Georgia PSC reconsider part of of its order relating to the price of energy strips. The outcome of this matter cannot now be determined.

(O) SOUTHERN's reportable business segment is the five integrated Southeast utilities that provide electric service in four states. Net income and total assets for discontinued operations are included in the Reconciling Eliminations columns. The All Other category includes parent SOUTHERN, which does not allocate operating expenses to business segments, and segments below the quantitative threshold for separate disclosure. These segments include telecommunications, energy products and services, and leasing and financing services. Intersegment revenues are not material. Financial data for business segments and products and services for the periods covered in the Form 10-Q are as follows:

	Integrated Southeast Utilities	All Other	Reconciling Eliminations	Consolidated
			(in millions)	
Three Months Ended March 31, 2001:				
Operating revenues	$ 2,221	$ 49	$ -	$ 2,270
Segment net income (loss)	199	(19)	140	320
Total assets at March 31, 2001	27,203	2,284	2,040	31,527
Three Months Ended March 31, 2000:				
Operating revenues	$ 2,005	$ 57	$ (10)	$ 2,052
Segment net income (loss)	176	(23)	92	245
Total assets at December 31, 2000	26,917	2,200	2,245	31,362

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

(1) Reference is made to the Notes to the Condensed Financial Statements herein for information regarding certain legal and administrative proceedings in which SOUTHERN and its reporting subsidiaries are involved.

Item 6. Exhibits and Reports on Form 8-K.

(a) Exhibits.

Exhibit 24 - (a) Powers of Attorney and resolutions. (Designated in the Form 10-K for the year ended December 31, 2000, File Nos. 1-3526, 1-3164, 1-6468, 0-2429, 0-6849 and 1-5072 as Exhibits 24(a), 24(b), 24(c), 24(d), 24(e) and 24(f), respectively, and incorporated herein by reference.)

(b) Reports on Form 8-K.

SOUTHERN, ALABAMA, GEORGIA, GULF, MISSISSIPPI and SAVANNAH filed Current Reports on Form 8-K dated February 28, 2001:

Items reported: Item 7
Financial statements filed: Each registrant's financial statements for the year ended December 31, 2000.

SOUTHERN filed Current Reports on Form 8-K dated February 19, 2001, March 2, 2001, March 6, 2001 and March 22, 2001:

Items reported: Item 9
Financial statements filed: None

SOUTHERN filed a Current Report on Form 8-K dated April 2, 2001:

Items reported: Items 2, 7 and 9
Financial statements filed: Pro Forma Financial Information.

GEORGIA filed Current Reports on Form 8-K dated January 26, 2001, February 16, 2001 and May 1, 2001:

Items reported: Items 5 and 7
Financial statements filed: *None*

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By *H. Allen Franklin*
Chairman and Chief Executive Officer
(Principal Executive Officer)

By *Gale E. Klappa*
Financial Vice President, Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer)

By /s/ Wayne Boston
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By *Elmer B. Harris*
Chairman and Chief Executive Officer
(Principal Executive Officer)

By *William B. Hutchins, III*
Executive Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

By /s/ Wayne Boston
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By *David M. Ratcliffe*
President and Chief Executive Officer
(Principal Executive Officer)

By *Thomas A. Fanning*
Executive Vice President, Treasurer and Chief Financial Officer
(Principal Financial Officer)

By */s/ Wayne Boston*
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By *Travis J. Bowden*
President and Chief Executive Officer
(Principal Executive Officer)

By *Ronnie Labrato*
Comptroller and Chief Financial Officer
(Principal Financial and Accounting Officer)

By */s/ Wayne Boston*
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By *Michael D. Garrett*
President and Chief Executive Officer
(Principal Executive Officer)

By *Michael W. Southern*
Vice President, Secretary, Treasurer and Chief Financial Officer
(Principal Financial and Accounting Officer)

By */s/ Wayne Boston*
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SAVANNAH ELECTRIC AND POWER COMPANY

By *Anthony R. James*
President and Chief Executive Officer
(Principal Executive Officer)

By *Kirby R. Willis*
Vice President, Treasurer and Chief Financial Officer
(Principal Financial and Accounting Officer)

By */s/ Wayne Boston*
(Wayne Boston, Attorney-in-fact)

Date: May 14, 2001

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FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Supply the results of the most recent FERC audit finding and compliance steps undertaken.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		___ Projected Test Year Ended 5/31/03
		___ Prior Year Ended 5/31/02
		XX Historical Test Year Ended 12/31/00
DOCKET NO.: 010949-EI		Witness: R. R. Labrato

Attached is the most recent FERC audit finding.

Supporting Schedules: Recap Schedules:

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

In Reply Refer To:
OCA-DOA
Docket Nos. FA95-23-000
and FA95-23-001

MAY 16 1997

Gulf Power Company
Attention: Mr. Ronnie R. Labrato
Controller
500 Bayfront Parkway
Pensacola, FL 32501

Ladies and Gentlemen:

The Division of Audits of the Office of the Chief Accountant has examined the books and records of Gulf Power Company for the period January 1, 1989, through December 31, 1994. The purpose of the examination was to evaluate your Company's compliance with Commission accounting and reporting regulations contained in the Uniform System of Accounts, Annual Report FERC Form No. 1, and the related regulations. The examination included selective tests of the accounting records, review of the internal control structure, and other tests and procedures considered necessary under the circumstances.

The Division of Audits did not recommend any corrective action related to the Company's compliance with the Commission's accounting, financial reporting, and tariff billing regulations. The attached audit report notes one issue related to the Company's accounting classificaiton for service company billings. The service company billing issue, which is deferred for further study, has been assigned as Docket No. FA95-23-001.

The Commission delegated authority to act in this matter to the Director, Division of Audits under 18 C.F.R. § 375.303. This letter order constitutes final agency action on the corrective actions approved and directed in this report. Within 30 days of the date of this order, your Company may file a request for rehearing with the Commission under 18 C.F.R. § 385.713.

This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

Sincerely,

Joseph A. Frangipane
Director, Division of Audits

Enclosure

Results of the Examination

of the

Books and Records

of

GULF POWER COMPANY
Docket Nos. FA95-23-000
and FA95-23-001

For the Period

1/1/89 through 12/31/94

Conducted by

Division of Audits
Office of the Chief Accountant
Federal Energy Regulatory Commission

DEFERRED MATTER

The Division of Audits deferred any recommendations related to the following matter:

1. Accounting Classification for Service Company Billings

SCS is a subsidiary of The Southern Company. SCS provides various services to the Company and other Southern Company subsidiaries, including system planning, engineering, financial, accounting, public affairs, fuel procurement, bulk power sales, etc.

SCS is subject to the Public Utility Holding Company Act (PUCHA) administered by the Securities and Exchange Commission (SEC). SCS maintain the accounts on the basis of the Uniform System of Accounts established by the SEC for mutual service companies.

SCS first assigns all costs to various expense and other accounts. Then, it assigns all direct and indirect costs to various billable projects or work orders. Direct costs include labor and labor fringes, such as payroll taxes and employee benefits. Indirect amounts include overhead amounts not specifically assignable to the work orders, such as administrative and general salaries, pensions, injuries and damages, miscellaneous general expenses, maintenance of general plant, etc.

SCS's invoices rendered to the Company and other Southern company subsidiaries include a cost breakdown for each work order between direct and overhead costs. The Company uses the accounting classifications provided by SCS to assign costs to its various accounts. Under this procedure, the Company classified certain SCS administrative and general expenses payroll taxes, etc., to accounts other than those to which they would be assigned if it directly incurred the expenditures. For example, charges for direct labor costs to particular projects and accounts included additional costs related to employment taxes, pensions, other employee benefits, administrative and general expenses, etc.

Discussion of Accounting Requirements

General Instruction No. 14, Transactions with Associated Companies, of the Uniform System of Accounts states:

> Each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies. The statements

may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. **Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature.** Nothing herein contained, however, shall be construed as restraining the utility from subdividing accounts for the purpose of recording separately transactions with associated companies. [Emphasis added.]

The intent of this instruction is to require an operating company to classify costs billed to it by an associated company in the same accounts as it directly incurred the costs. This supports the concept underlying the FERC's accounting requirements that an associated service company is in essence an extension of the company and not a separate entity. Therefore, a jurisdictional company would use the same accounting classification for a cost whether it or its affiliate provided the service. Consistency in the accounting classification of similar costs is important because of the different manner a company recovers the various costs components in rates.

The Office of the Chief Accountant is currently studying the issue of classification of affiliated company charges on an industry-wide basis. Therefore, the Division of Audits did not make any further recommendations on the subject pending completion of the study and any resulting FERC action. The accounting for the classification of affiliated company charges will be resolved in a separate docket, Docket No. FA95-23-001.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of directors of company showing 1) name; 2) principal business address; 3) date term began; 4) date term expires; 5) number of directors meetings attended in the test year; and 6) fees received during the test. If the test year is projected, use the prior year data for columns 5 and 6.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Name	(2) Principal Business Address	(3) Date Term Began	(4) Date Term Expires	(5) Number of Meetings Attended 12 Months Ended 12/31/00	(6) Fees Received
1.	C. LeDon Anchors	909 Mar Walt Dr., Suite 1014	May-01	Jun-02	0	$0.00
2.		Ft. Walton Beach, FL 32547-6711				
3.	Travis J. Bowden	One Energy Place	May-01	Jun-02	4	$0.00
4.		Pensacola, FL 32520-0100				
5.	Fred C. Donovan, Sr.	316 S. Baylen St., Suite 300	May-01	Jun-02	4	$22,869.49
6.		Pensacola, FL 32501				
7.	H. Allen Franklin	270 Peachtree St.	May-01	Jun-02	0	$0.00
8.		Atlanta, GA 30303				
9.	W. Deck Hull, Jr.	P. O. Box 2266	May-01	Jun-02	4	$21,960.87
10.		Panama City, FL 32402				
11.	Barbara H. Thames	4654 Carlyn Dr.	May-01	Jul-01	4	$22,869.49
12.		Pace, FL 32571				
13.	Joseph K. Tannehill	10 Arthur Dr.	May-01	Jun-02	3	$16,619.62
14.		Lynn Haven, FL 32444				
15.	William A. Pullum	8494 Navarre Parkway	Jul-01	Jun-02	0	$0.00
16.		Navarre, Florida 32566				
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Alabama Power Company		600 North 18th Street
2.			Birmingham, AL 35203
3.			
4.	Chairman & Chief Executive Officer	Elmer B. Harris	
5.	President & Chief Operating Officer	Charles D. McCrary	
6.	Executive Vice President, Chief Financial	William B. Hutchins, III	
7.	Officer and Treasurer		
8.	Executive Vice President	C. Alan Martin	
9.	Executive Vice President	Steven R. Spencer	
10.	Senior Vice President	Robert Holmes, Jr.	
11.	Senior Vice President	Robin A. Hurst	
12.	Senior Vice President & Counsel	Rodney O. Mundy	
13.	Senior Vice President	Michael L. Scott	
14.	Senior Vice President	Jerry L. Stewart	
15.	Senior Vice President	Christopher C. Womack	
16.	Vice President & Comptroller	Arthur P. Beattie	
17.	Vice President	Christopher T. Bell	
18.	Vice President-Birmingham Division	Marsha S. Johnson	
19.	Vice President	J. Bruce Jones	
20.	Vice President	William B. Keller	
21.	Vice President & Chief Information Officer	Penny M. Manuel	
22.	Vice President	Donald W. Reese	
23.	Vice President	Julian H. Smith, Jr.	
24.	Vice President, Secretary & Assistant Treasurer	William E. Zales, Jr.	
25.	Vice President-Eastern Division	W. Ronald Smith	
26.	Vice President-Southeastern Division	Bobby J. Kerley	
27.	Vice President-Southern Division	Gordon Martin	
28.	Vice President-Mobile Division	Cheryl G. Thompson	
29.	Vice President-Western Division+B151	Terry H. Waters	
30	Assistant Comptroller	Robert Cole Giddens	
31.	Assistant Secretary & Assistant Treasurer	E. Wayne Boston	
32.	Assistant Secretary	Stuart L. Griffin	
33.	Assistant Secretary	Ceila H. Shorts	
34.	Assistant Treasurer	J. Randy DeRieux	

Supporting Schedules: Recap Schedules:

11

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Georgia Power Company		241 Ralph McGill Boulevard, N.E.
2.			Atlanta, GA 30308-3374
3.			
4.	President & Chief Executive Officer	David M. Ratcliffe	
5.	Executive Vice President	William C. Archer, III	
6.	Executive Vice President, Treasurer &	Thomas A. Fanning	
7.	Chief Financial Officer		
8.	Senior Vice President	Judy M. Anderson	
9.	Senior Vice President	M. A. Brown	
10.	Senior Vice President	James K. Davis	
11.	Senior Vice President	Robert H. Haubein	
12.	Senior Vice President	Fred D. Williams	
13.	Vice President	David R. Altman	
14.	Vice President - Transmission	Ronnie L. Bates	
15.	Vice President	Robert L. Boyer	
16.	Vice President - Region Operations	A. Bryan Fletcher	
17.	Vice President	J. Kevin Fletcher	
18.	Vice President - Environmental Affairs	Chris M. Hobson	
19.	Vice President- Governmental and	Ed. F. Holcombe	
20.	Regulatory Affairs		
21.	Vice President	Richard L. Holmes	
22.	Vice President	E. Lamont Houston	
23.	Vice President, Administrative Services	Anne H. Kaiser	
24.	Vice President of Diversity	Frank J. McCloskey	
25.	Vice President of Information Services	C. Philip Saunders	
26.	Vice President, Comptroller & Chief	Cliff S. Thrasher	
27.	Accounting Officer		
28.	Vice President	Jeffrey L. Wallace	
29.	Vice President	Christopher C. Womack	
30.	Corporate Secretary	Janice G. Wolfe	
31.	Assistant Comptroller & Assistant Secretary	W. Ron Hinson	
32.	Assistant Secretary & Assistant Treasurer	E. Wayne Boston	

Supporting Schedules: Recap Schedules:

12

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Georgia Power Company (con't.)		241 Ralph McGill Boulevard, N.E.
2.			Atlanta, GA 30308-3374
3.			
4.	Assistant Treasurer	Allen L. Leverett	
5.	Vice President of Community & Economic	Rebecca A. Blalock	
6.	Development		
7.	Vice President of Land	O. Ben Harris	
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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Mississippi Power Company		2992 West Beach Boulevard
2.			Gulfport, MS 39501
3.			
4.	President & Chief Executive Officer	Michael D. Garrett	
5.	Vice President	H. E. Blakeslee	
6.	Vice President	Don E. Mason	
7.	Vice President	Michael L. Scott	
8.	Vice President, Secretary, Treasurer &	Michael W. Southern	
9.	Chief Financial Officer		
10.	Vice President	Gene L. Ussery, Jr.	
11.	Vice President	Christopher C. Womack	
12.	Comptroller	Frances V. Turnage	
13.	Asisstant Secretary & Assistant Treasurer	E. Wayne Boston	
14.	Asisstant Secretary & Assistant Treasurer	Vicki L. Pierce	
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Supporting Schedules: Recap Schedules:

Schedule F-6 | OFFICERS OF AFFILIATED COMPANIES OR SUBSIDIARIES |

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Savannah Electric and Power Company		600 East Bay Street
2.			Savannah, GA 31401
3.			
4.	President & Chief Executive Officer	Anthony R. James	
5.	Vice President - Customer Operations &	W. Miles Greer	
6.	External Affairs		
7.	Vice President	Leonard J. Haynes	
8.	Vice President - Power Generation	Sandra R. Miller	
9.	Vice President, Chief Financial Officer,	Kirby R. Willis	
10.	Treasurer & Assistant Secretary		
11.	Vice President	Christopher C. Womack	
12.	Corporate Secretary	Nancy E. Frankenhauser	
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Supporting Schedules: | Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Southern Company Services, Inc.		241 Ralph McGill Blvd., N.E.
2.			Atlanta, GA 30308-3374
3.			
4.	President & Chief Executive Officer	H. Allen Franklin	
5.	Executive Vice President	William Paul Bowers	
6.	Executive Vice President	Dwight H. Evans	
7.	Executive Vice President	Leonard J. Haynes	
8.	Executive Vice President	G. Edison Holland, Jr.	
9.	Executive Vice President	Gale E. Klappa	
10.	Executive Vice President	Susan N. Story	
11.	Senior Vice President	Andy J. Dearman, III	
12.	Senior Vice President	Charles H. Goodman	
13.	Senior Vice President	Robert H. Haubein	
14.	Senior Vice President, Comptroller &	W. Dean Hudson	
15.	Chief Financial Officer		
16.	Senior Vice President	William K. Newman	
17.	Senior Vice President	C. Philip Saunders	
18.	Senior Vice President	Michael L. Scott	
19.	Senior Vice President	Jerry L. Stewart	
20.	Senior Vice President	Stephen A. Wakefield	
21.	Senior Vice President	Christopher C. Womack	
22.	Vice President	David R. Altman	
23.	Vice President	Robert A. Bell	
24.	Vice President	Robert L. Boyer	
25.	Vice President	Ronald R. Campbell	
26.	Vice President & Secretary	Tommy Chisholm	
27.	Vice President	David L. Coker	
28.	Vice President	James M. Corbitt	
29.	Vice President	James C. Fleming	
30.	Vice President	Barbara S. Hingst	
31.	Vice President	Douglas E. Jones	
32.	Vice President & Treasurer	Allen L. Leverett	
33.	Vice President	Charles D. Long, IV	
34.	Vice President	Jacqualyn W. Lowe	

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Southern Company Services, Inc. (con't.)		241 Ralph McGill Blvd., N.E.
2.			Atlanta, GA 30308-3374
3.			
4.	Vice President	William L. Marshall, Jr.	
5.	Vice President	Christopher S. Miller	
6.	Vice President	Joseph A. Miller	
7.	Vice President	Sandra R. Miller	
8.	Vice President	Karl R. Moor	
9.	Vice President	Robert G. Moore	
10.	Vice President	Rodney O. Mundy	
11.	Vice President	Earl B. Parsons, III	
12.	Vice President	Anthony J. Topazi	
13.	Vice President	Gene L. Ussery, Jr.	
14.	Vice President	Stephen A. Wakefield	
15.	Assistant Comptroller & Assistant Secretary	E. Wayne Boston	
16.	Assistant Secretary	Samuel C. Campisi	
17.	Assistant Secretary	Sam H. Dabbs, Jr.	
18.	Assistant Treasurer	Christopher J. Kysar	
19.	Assistant Treasurer	Earl C. Long	
20.	Assistant Treasurer	Roger S. Steffens	
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Southern Communications Services, Inc.		Glenridge One Building
2.			5555 Glenridge Connector
3.			Suite 500
4.	President & Chief Executive Officer	Robert G. Dawson	Atlanta, GA 30342
5.	Vice President, Treasurer & Chief Financial	R. Craig Elder	
6.	Officer		
7.	Vice President	Rodney H. Johnson	
8.	Vice President	T. Julie Pigott	
9.	Comptroller	Carmine A. Reppucci	
10.	Secretary	Tommy Chisholm	
11.	Assistant Secretary	John P. Batts, Jr.	
12.	Assistant Secretary	Sam H. Dabbs, Jr.	
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Southern Company Energy Solutions, LLC		4000 KeKalb Technology Pkwy.
2.			Suite 100
3.			Atlanta, GA 30340
4.	President	Bertram E. Sears	
5.	Vice President	Michael E. Ellis	
6.	~~Secretary~~	~~Tommy Chisholm~~	
7.	Treasurer	Allen L. Leverett	
8.	Assistant Secretary	Sam H. Dabbs, Jr.	
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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) name; and 3) principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	Southern Telecom, Inc.		3003 Summit Boulevard
2.			Suite 700
3.			Atlanta, GA 30319-1470
4.	President & Chief Executive Officer	Robert G. Dawson	
5.	Secretary	Tommy Chisholm	
6.	Treasurer	R. Craig Elder	
7.	Assistant Secretary	Sam H. Dabbs, Jr.	
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Supporting Schedules: | Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of officers of affiliated companies or subsidiaries which provide goods or services to the applicant or its affiliates showing, 1) title; 2) names; and principal business address.

Type of Data Shown:
_ Projected Test Year Ended 5/31/03
_ Prior Year Ended 5/31/02
_ Historical Year 12/31/00
Witness: R. R. Labrato

Line No.	(1) Title	(2) Name	(3) Principal Business Address
1.	The Southern Company		270 Peachtree Street, N.W.
2.			Atlanta, GA 30303
3.			
4.	Chairman of the Board, President	H. Allen Franklin	
5.	& Chief Executive Officer		
6.	Executive Vice President	Dwight H. Evans	
7.	Executive Vice President	Elmer B. Harris	
8.	Executive Vice President	Leonard J. Haynes	
9.	Executive Vice President	G. Edison Holland, Jr.	
10.	Executive Vice President, Chief Financial	Gale E. Klappa	
11.	Officer and Treasurer		
12.	Executive Vice President	David M. Ratcliffe	
13.	Vice President	David R. Altman	
14.	Vice President	Joseph A. Miller	
15.	Vice President	Christopher C. Womack	
16.	Comptroller	W. Dean Hudson	
17.	Secretary & Assistant Treasurer	Tommy Chisholm	
18.	Assistant Comptroller	Timothy L. Faltaw	
19.	Assistant Secretary	Patricia L. Roberts	
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Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide a schedule of business contracts entered into by the applicant with its officers, directors, or firms, partnerships and organizations with which officers or directors are affiliated. Provide the requested information or the test year. If the test year is projected, use the prior year.

Type of Data Shown:
__ Projected Test Year Ended 5/31/03
__ Prior Year Ended 5/31/02
XX Historical Year 12/31/00
Witness: R. R. Labrato

Name of Officer or Director	Name and Address of Affiliated Entity	Relationship With Affiliated Entity	Amount of Contract or Transaction	Description of Product or Service
Fred C. Donovan, Sr.	Baskerville-Donovan, Inc. 316 South Baylen St. Suite 300 Pensacola FL 32501	President/CEO	$9,236.00	Surveyor Services
	Baptist Health Care, Inc. 1010 West Blount Street Pensacola FL 32522	Director	$1,294.05	Health Care Services
Joseph K. Tannehill	Merrick Industries, Inc. 10 Arthur Drive Lynn Haven FL 32444	Chairman, CEO & Owner	$244,055.63	Electric Equipment
	Merrick Environmental Tech, Inc. 10 Arthur Drive Lynn Haven FL 32444	Chairman, CEO & Owner	$67,919.79	Electric Equipment
	Regions Bank of North Florida Panama City FL	Director	$7,500.00	Line of Credit
Barbara H. Thames	West Florida Regional Medical Ctr 8383 N Davis Highway Pensacola Fl 32514	Chief Operating Officer	$39,561.22	Medical Services

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide a schedule of business contracts entered into by the applicant with its officers, directors, or firms, partnerships and organizations with which officers or directors are affiliated. Provide the requested information for the test year. If the test year is projected, use the prior year.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		__ Projected Test Year Ended 5/31/03
		__ Prior Year Ended 5/31/02
		XX Historical Year 12/31/00
DOCKET NO.: 010949-EI		Witness: R. R. Labrato

Line No.	Name of Officer or Director	Name and Address of Affiliated Entity	Relationship With Affiliated Entity	Amount of Contract or Transaction	Description of Product or Service
1.	Travis J. Bowden	Amsouth Bank of Florida	Director	$13,680.22 (1)	Banking Services and
2.		P.O. Box 12790			Line of Credit
3.		Pensacola FL 32575			
4.					
5.		Baptist Health Care, Inc.	Director	$1,294.05	Health Care Services
6.		1010 West Blount Street			
7.		Pensacola FL 32522			
8.					
9.					
10.	Francis M. Fisher, Jr.	First Union Bank	Director	$30,262.88 (1)	Banking Services
11.		P.O. Box 12750			
12.		Pensacola FL 32575			
13.					
14.					
15.	C. LeDon Anchors, Esquire	Regions Bank of Okaloosa County	Director, Chairman of the Board	$7,500.00	Line of Credit
16.		2 NE Eglin Parkway			
17.		Fort Walton Beach FL 32548			
18.					
19.		Anchors Foster McInnis & Keefe, PA	President, Director	$1,350.00	Attorneys at Law
20.		909 Mar Walt Drive			
21.		Fort Walton Beach FL 32547			
22.					
23.					
24.	William Allen Pullum	Whitney National Bank of Florida	Director	$8,372.52 (1)	Banking Services and
25.		101 W Garden Street			Line of Credit
26.		Pensacola FL 32501			
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34.	(1) Maintain Demand Deposit Account				

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 010949-EI	EXPLANATION: Supply a copy of all NRC safety citations issued against the company within the last two years, a listing of corrective actions and a listing of any outstanding deficiencies. For each citation provide the dollar amount of any fines or penalties assessed against the company and account(s) each are recorded.	Type of Data Shown: ___ Projected Test Year Ended 5/31/03 ___ Prior Year Ended 5/31/02 ___ Historical Year Ended 12/31/00 Witness: R. G. Moore

Not applicable. Gulf has no nuclear facilities.

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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

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Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R. M. Saxon

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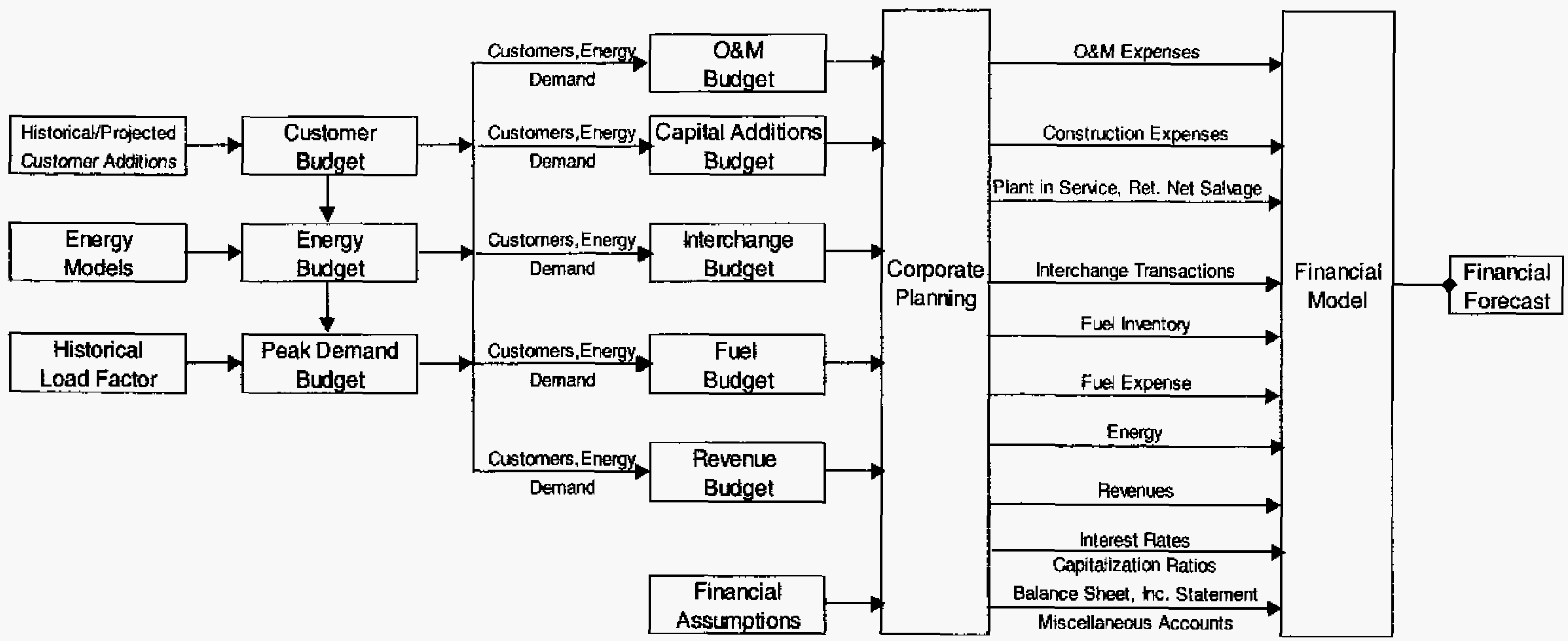
GULF POWER PLANNING / BUDGETING FLOW CHART



FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

I. OVERVIEW

This schedule describes the process Gulf Power uses in developing its annual financial forecast. The financial forecast is comprised of eight component budgets which are used by management to assess departmental performance and to control the Company's operations and activities. Gulf's financial forecast is a logically developed and detailed tool that management uses in making decisions affecting the future direction of the Company.

Gulf's forecasting process is outlined on the flow chart on page 2 of this schedule. The chart shows the process beginning with information obtained by the Marketing Department which leads to the development of the customers, energy, and demand budgets. These budgets in turn provide the basis for developing the revenue, fuel, interchange, Capital Additions, and Operations and Maintenance budgets. The chart does not indicate the numerous management reviews and approvals of each budget, nor does it show approval of the construction budget by the Board of Directors.

Many assumptions are incorporated in the eight component budgets of Gulf's financial forecast. Parameter assumptions to be used as guidelines for budgeting are provided to all departments by Corporate Planning. Additionally, assumptions are made as each department develops its own budget. A listing of these assumptions is contained on MFR Schedule F-17.

The information and budgets developed by this process are input to Gulf's Financial Model which utilizes the inputs and generates the accounting statements that comprise the Company's financial forecast. With a few adjustments, as described by Mr. Labrato in his testimony, the financial forecast becomes useful for rate making purposes, providing Gulf's 2002 & 2003 financial data as used in this proceeding.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R. M. Saxon

II. CUSTOMER, ENERGY, AND PEAK DEMAND FORECAST

Methodology Overview

Gulf Power Company views the forecasting effort as a dynamic process requiring ongoing efforts to yield results which allow informed planning and decision making. The total forecast is an integration of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts, which are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of our customers and actively promoting wise and efficient uses of energy which satisfy customer needs. This philosophy entails focused market research efforts, coupled with marketing programs aimed at providing our customers with the information needed to make sound energy decisions.

The Marketing Services section of the Marketing and Load Management Department is responsible for preparing forecasts of customers, energy, peak demand and base rate revenues. Forecasts of monthly customers, energy sales, supply and peak demand are produced for both the short-term (0 - 2 years) and long- term (3 - 25 years). Base rate revenue projections are prepared for the short-term horizon.

All of the methods employed in this forecast are consistent with those used in the Company's most recent ten-year site plan. Since the primary focus in this proceeding is on the test year, this description will center on the short-term forecast methods and models that were employed to develop the test year projections.

Customer Forecast

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by Gulf's district Marketing personnel based upon recent historical trends in customer gains and their knowledge of locally planned construction projects from which they are able to estimate the near-term anticipated monthly customer additions. These projections are then analyzed for consistency and the incorporation of major construction projects and business developments, and reviewed for completeness and accuracy. The end result is a near-term forecast of monthly customers for each rate within each of the customer classes for which Gulf provides service.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. L. McGee

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Residential Sales Forecast

The short-term residential energy sales forecast is developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather (heating and cooling degree hours), seasonal variations and projected price of electricity. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total residential class. The residential class energy projections are then adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan.

Commercial Sales Forecast

The short-term (0-2 years) commercial energy sales forecast is also developed utilizing multiple regression analyses. Monthly class energy use per customer per billing day is estimated based upon recent historical data, expected normal weather (heating and cooling degree hours), seasonal variations and projected price of electricity. The model output is then multiplied by the projected number of customers and billing days by month to expand to the total commercial class. The commercial class energy projections are then adjusted to reflect the anticipated incremental impacts of Gulf's DSM plan.

Industrial Sales Forecast

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Fifty-one of Gulf's largest industrial customers are interviewed to identify load changes due to equipment additions and replacements, or changes in operating characteristics. The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using a combination of trending techniques and multiple regression analysis by rate, as appropriate. The resulting estimates of energy use per customer per day are multiplied by the expected number of customers and billing days by month to expand to the rate level totals. These projections are then combined with the results for the major industrial customers to sum to the monthly industrial class and rate level totals.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. L. McGee

Street Lighting Sales Forecast

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service for each of the following fixture sizes:

HIGH PRESSURE SODIUM VAPOR	MERCURY VAPOR
5,400 Lumen	3,200 Lumen
8,800 Lumen	7,000 Lumen
20,000 Lumen	9,400 Lumen
25,000 Lumen	17,000 Lumen
46,000 Lumen	48,000 Lumen

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Within each of the above fixture sizes are variations that provide for different types of fixtures as well as levels of service. Each variation by fixture type is modeled individually. The estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury vapor to high pressure sodium vapor conversions.

Wholesale Energy Forecast

The forecast of energy sales to wholesale customers is developed utilizing multiple regression analyses. Monthly energy use per day for each of Gulf's wholesale customers is estimated based upon recent historical data, expected normal weather (heating and cooling degree hours) and seasonal variations. The model output is then multiplied by the projected number of days by month to expand to the customer totals, which are then summed to develop the class totals.

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. L. McGee

Company Use & Interdepartmental Energy

The forecast for Company energy usage was based on recent historical values. Annual energy usage was projected at the same growth rate each year as the compound average annual growth rate for the period from 1992 through 2000. The monthly spreads were derived using historical relationships between monthly and annual energy usage. Recent closure of Gulf's Appliance Sales has resulted in significant decreases in Interdepartmental energy usage. As a result of anticipated additional cutbacks, no Interdepartmental energy is projected beyond 2002.

Peak Demand Forecast

The short-term (0-2 years) peak demand forecast is prepared using average historical monthly territorial load factors and projected monthly territorial supply.

The summer peak month demand projections are based upon the average of the historical summer peak month territorial load factors for the period from 1980 through the summer peak of 2000, excluding the extreme high load factor and extreme low load factor experienced during that period. Gulf's summer peak demand typically occurs in the month of July.

Similarly, the winter peak month demand projections are based upon the average of the historical winter peak month territorial load factors for the period from 1980 through the summer peak of 2000, excluding the extreme high load factor and extreme low load factor experienced during that period. Gulf's winter peak demand typically occurs in the month of January.

The remaining monthly demand projections are developed in similar fashion utilizing the respective historical average monthly load factors, excluding the monthly extreme high and extreme low load factors.

The resulting monthly demand projections are then further refined by taking into account the impact of Gulf's DSM programs.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R. L. McGee, R. M. Saxon

III. REVENUE BUDGET

Gulf's Base Revenue Budget is developed by the Marketing Department with Corporate Planning providing the Other Operating Revenue portion and the Financial Model calculating the Fuel Revenue portion. The Base Revenue Budget is developed utilizing inputs from the Customer, Energy and Demand Budgets and the currently effective rates as approved by the FPSC at the time of the forecast.

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Base revenues are calculated by multiplying the:

(1) Projected monthly customers by rate schedule times the corresponding customer charge.
(2) Projected monthly kwh's by rate schedule times the appropriate energy rate.
(3) Projected monthly billing demand by appropriate rate schedule times the corresponding demand charge.

All appropriate discounts and contracted capacities are taken into account in making these calculations. In rate classes where revenues are calculated at the aggregate level rather than on an individual basis, the billing determinants are based upon average historical relationships. Base revenues are the summation of the above calculations.

Fuel, Purchased Power Capacity, and Environmental Clause revenues are calculated by the Financial Model using inputs from the Energy, Fuel and Interchange Budgets. The model calculates monthly factors based on energy and recoverable fuel, purchased power, and environmental expenses. These factors are then multiplied times the billed energy by rate class to arrive at the respective clause revenues. Conservation revenues are projected from the amount of recoverable conservation expenses included in the Operation and Maintenance Budget. A monthly factor based on energy and recoverable conservation expenses is multiplied times the billed and unbilled energy by rate class to arrive at conservation revenues.

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. L. McGee, R. M. Saxon

Net unbilled revenue is determined using inputs from the Energy, Fuel and Interchange Budgets, recoverable conservation expenses and the currently effective base rates. The appropriate following month's factor is multiplied by the accrued gross unbilled kwh for the current month. Netted against this calculation is the reversal of the prior month's accrued gross unbilled base revenue to produce the net unbilled base rate revenue. The appropriate factors for fuel, purchased power, environmental and conservation are multiplied times the monthly net unbilled energy adjustment to produce the net unbilled revenue for each of the recoverable clauses. The total net unbilled revenue is the summation of the net unbilled base rate, fuel, purchased power capacity, environmental and conservation revenues.

Other Operating Revenues include franchise fees, pole attachment and equipment rentals and miscellaneous other service revenue. Franchise fee reveneus are projected to equal the franchise fee expense which is calculated by the Financial Model. The remaining revenue items are projected by the Corporate Planning Department.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. G. Moore, M. W. Howell

IV. Overview of the Energy/Interchange Process

Description

The Energy/Fuel Budgets are an integral part of Gulf's Operating Budget and the budgets of each of the other Operating Companies within the Southern electric system. Data provided by the Energy/Fuel forecast includes unit capacity factors, unit performance, pool interchange, off-system sales, and fuel expenses.

The Energy Budget is produced using PROSYM, a computer model used to simulate the economic dispatch of the Southern electric system. Inputs to the model are provided by the Operating Companies and include unit data, loads and sales information. In addition, fuel cost data is provided by FOES, a Fuel Optimization and Evaluation System. The development of fuel costs for the Energy Budget is based on a computer iterative process. PROSYM determines the burn by unit based on a set of fuel costs. The burn then becomes input to FOES and new fuel costs are provided back to PROSYM. This process is repeated until the programs converge to a realistic solution. An Energy Budget process flowchart is shown on page 10 of this schedule.

Once the Energy/Fuel Budgets are complete, the results are provided to Financial Planning and other departments at each Operating Company to be incorporated into the Operating Budget.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

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Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R. G. Moore, M. W. Howell

The following is a brief description of the models utilized in the forecast:

Fuel Cost Model, Fuel Optimization and Evaluation System

The purpose of the fuel optimization and evaluation system program is to provide an economical dispatch of all the fossil fuels to the plants within the Southern electric system. The program receives as input the heat requirements in BTU's for each unit at a plant, the desired inventory level at each plant, and the availabilities of fuel supplies at each source or mine. Also, the cost of each fuel commodity and it's associated transportation costs are provided as inputs to the fuel model, including any applicable escalation of pricing over time. With this data, the program formulates and solves (minimizes cost) a transportation system using linear programming techniques. The program can dispatch a multitude of fuel sources to any given plant.

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Production Costing Model, PROSYM

Gulf Power Company and the Southern Electric system utilize the PROSYM, a chronological modeling system, to project future fuel requirements and system production costs. PROSYM is a complete electric utility/regional pool analysis and accounting system. This model is designed for performing planning and operational studies, and as a result of its chronological structure, the model accommodates detailed investigations of operations of electric utilities with power pools such as the Southern Electric System pool.

The basic PROSYM inputs include data related to generating units, fuel costs, demand and energy, and system operating characteristics. The basic outputs are energy produced and BTU requirements for each generating unit.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. G. Moore, M. W. Howell

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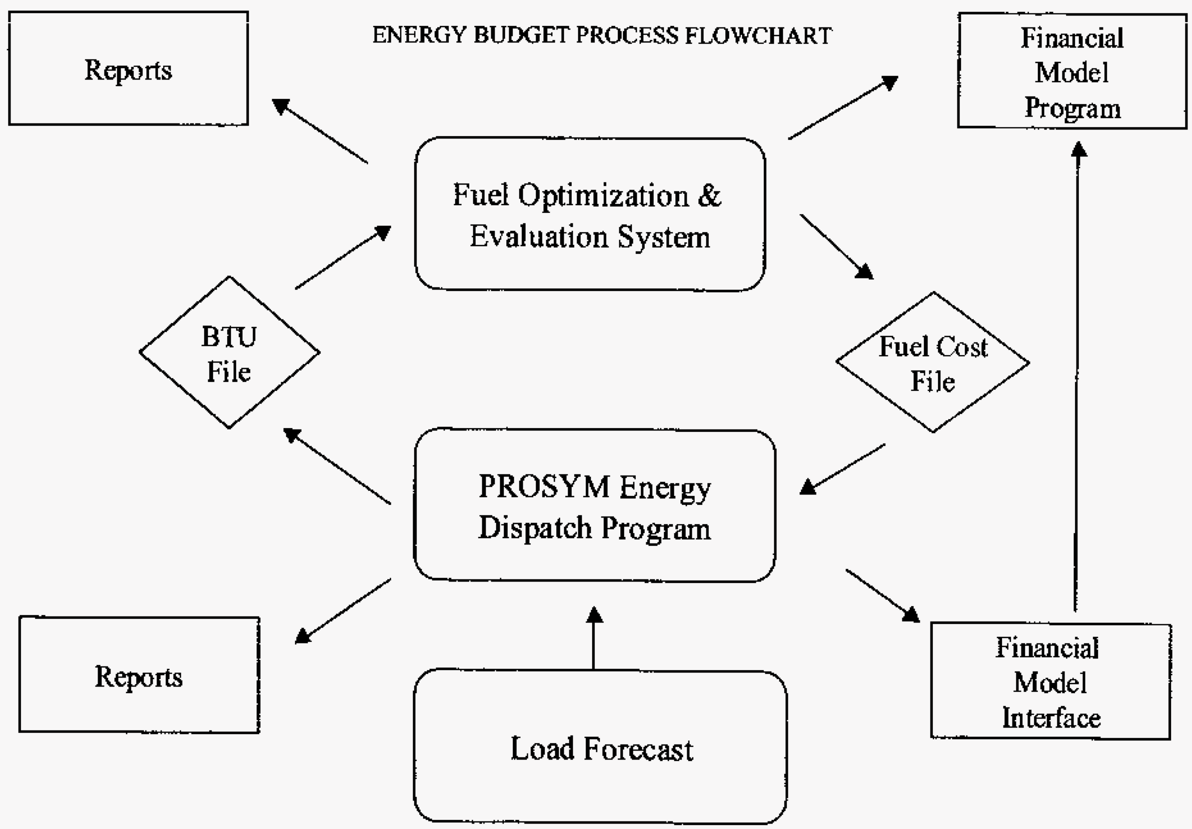
ENERGY BUDGET PROCESS FLOWCHART



Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

V. CONSTRUCTION BUDGET

A. Construction Expenditures

Gulf's construction requirements are determined through a detailed analysis of existing facilities and projections of customer growth, energy, demand, and patterns of energy usage. The construction budget is driven off inputs obtained from the Customer, Energy, and Demand Budgets and is comprised of the following components:

(1) Major Generation and Production Plant Analysis. Utilizing inputs from the budgets mentioned above, the need for and timing of major generation additions necessary to maintain reliable service is projected. The resulting Generation Expansion Plan is coordinated with associated operating companies such that projected customer requirements are met, total system construction dollars are effectively utilized and economies of scale are realized. Other production plant additions are based on deterioration of existing facilities, operating experience, environmental requirements, and necessary expansions.

(2) Distribution Analysis. The results of monitoring circuit loads on the Gulf system and the inputs from the Customer, Energy, and Demand Budgets are utilized in studies which project the need for and timing of additions to Gulf's distribution system.

(3) Transmission Analysis. Combines the results of the major generation and distribution analysis and the inputs from the three budgets mentioned above to determine future transmission facility requirements.

(4) General facilities Analysis. Involves combining periodic reviews of existing facilities, equipment, and their related costs with the information obtained from the Customer, Energy, and Demand Budgets in projecting future general facility requirements.

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

These analyses are reviewed by the appropriate members of management and a construction plan for each function is established. The details of the construction plan are communicated to the affected departments and become the foundation for scheduling projects and budgeting the related expenditures. Each project, its justification, and related costs are summarized as Plant Expenditure items (P.E.'s). The P.E.'s are reviewed and approved by the appropriate managers, and officers. The P.E.'s are then summarized by Corporate Planning and presented to the Leadership Team for its review and approval. Once approved by the Leadership Team, the Construction Budget is reviewed and approved by the Chief Executive Officer prior to submitting it to the Board of Directors. After the Board has approved the Construction Budget, the information contained in the budget is input to the Financial Model.

B. Plant - In - Service

Each P.E. contains pertinent information such as the project's functional classification, supporting detail, starting date and completion date expenditures, clearings to service, retirements, and cost of removal and salvage by month and year. The P.E. may contain one or more projects with varying completion dates. The monthly breakdown of expenditures, clearings to service, retirements, cost of removal and salvage for the budget year and the forecast years are input to the Financial Model which calculates the various plant balances on a monthly basis.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

VI. OPERATION AND MAINTENANCE EXPENSES WITHOUT FUEL OR PURCHASED POWER

The development of Gulf's Operation and Maintenance Budget (O&M), which excludes Direct Fuel and Purchased Power, begins with the developing of Strategic Issues facing the Company. These issues are then developed into a Company -wide Strategic Business Plan. The Chief Financial Officer then reviews the budgeted revenues forecasted for the period and develops a Budget Message that outlines the goals and objectives of the Company and gives specific guidelines to the Planning Units to develop their budgets and forecasts.

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Upon receipt of the Budget Message each department prepares the detailed budget that supports its approved goals and objectives for the budget year. The budget represents the funds the department management determines are required to accomplish its goals and objectives. The Senior Officer reviews the budget prior to it being submitted to Corporate Planning.

Corporate Planning reviews submittals for compliance with the Company guidelines and compiles the data for review by the Chief Financial Officer and the Leadership Team. Any changes are documented and then the approved budget is sent to the Planning Units.

Each Planning Unit monitors their budget to actual comparison using the accounting reporting on-line system referred to as Southern Financial Information Access System (SOFIA). Quarterly reports are required that explain any variance plus or minus 10 percent and the variance amount is greater than or equal to plus or minus $25,000. Year-end projections are also received from each Planning Unit.

The Corporate Planning Department is responsible for coordinating the O&M Budget process, providing the necessary information to the Chief Financial Officer and the Leadership Team.

The O&M Budget reflects the Company's best expectations of the cost of providing service in conformity to the overall Strategic Plan. The O&M Budget is also one standard by which a specific department's performance is evaluated.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.

Type of Data Shown:
XX Projected Test Year Ended 05/31/03
___ Prior Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R. M. Saxon

VII. FINANCIAL MODEL

Gulf's Financial Model is a complex and detailed computer based model that closely simulates Gulf's actual financial/accounting practices.

Information contained in the approved budgets developed by Gulf's planning process (see page 2 of this schedule) is input to the model as follows:

(1) Energy Budget. The Energy Budget is interfaced with the financial model and is used in conjunction with the Fuel and Interchange Budgets in developing fuel revenues on the income statement. The Energy Budget is described in Section II of this schedule.

(2) Fuel Budget. The Fuel Budget is produced by the FOES and PROSYM models as described in section IV of this schedule, which interface with the financial model. The Fuel Budget contains the projected fuel expense that is included on the financial model's income statement and the projected fuel stockpile amounts that are included on the balance sheet. The Fuel Budget also operates in conjunction with the Energy and Interchange Budgets in projecting the fuel revenues included on the income statement. Additionally, the Fuel Budget is used in deriving a portion of the Other Accounts Payable account contained on the balance sheet.

(3) Interchange Budget. The Interchange Budget is produced by the FOES and PROSYM models as described in section IV of this schedule, which interface with the Financial Model. The Interchange Budget provides the non-territorial sales and purchased power transactions that appear on the model's income statement. In conjunction with the Energy and Fuel Budgets, the Interchange Budget is used to project the Fuel and Capacity Revenues on the income statement. The Interchange Budget is also used in calculating a portion of the Associated Companies Accounts Receivable, Associated Companies Accounts Payable and a portion of the Other Accounts Payable account contained on the balance sheet.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: If a projected test year is used, provide a brief description of each method or model used in the forecasting process. Provide a flow chart which shows the position of each model in the forecasting process. Provide under separate cover to staff, Commissioners, Commission Clerk, and, upon request, other parties to this docket a detailed description of the complete forecasting model used to provide the forecasts of the number of customers, energy sales and peak demands submitted in Schedules E-27a, E-27b, and E-27c. This description shall include the method(s) used to calculate and validate the model(s). A description of the differences between this forecasting model and that used in the Commission's most recent planning hearing shall be included.	Type of Data Shown: XX Projected Test Year Ended 05/31/03 ___ Prior Year Ended 05/31/02 ___ Historical Test Year Ended 12/31/00 Witness: R. M. Saxon

(4) Revenue Budget. The Revenue Budget is directly input to the financial model as base rate revenues. The Revenue Budget as described in section III of this schedule, is contained on the income statement of the model and is used in calculating numerous other items on the income statement and balance sheet.

(5) Construction Budget. The Construction Budget is utilized in projecting the Plant - In - Service, Plant Held for Future Use, CWIP, Accumulated Depreciation, and Construction Related Accounts Payable accounts. The Construction Budget is described in section V of this report.

(6) Operations and Maintenance Budget (without Direct Fuel and Purchased Power). The Operations and Maintenance Budget is directly input to the financial model's income statement and is utilized in deriving a portion of the Other Accounts Payable account on the balance sheet. The O & M Budget is described in section VI of this schedule.

Other inputs to the financial model such as miscellaneous balance sheet accounts and miscellaneous revenue and expense items are developed by the Corporate Planning Department using trend-line methodologies and expertise from other departments. Corporate Planning also coordinates the running of the model and is responsible for initiating the necessary changes of the model's logic.

The Financial Model is constantly undergoing modifications and enhancements in response to the changing conditions in the utility industry. These adjustments enable the model to continue as an effective tool for use by management in planning and decision-making as well as providing information (with a few adjustments) that is useful for rate making purposes.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: If a projected test year is used for each load, fuel cost or sales forecasting model, give a quantified explanation of the impact of changes in the inputs to changes in outputs.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
____Historical Year Ended 12/31/00
Witness: R. L. McGee

Model: Residential Energy

Line No.	Input Variable	Percent Change (Input)	Output Variable Affected	Percent Change (Output)
1.	Residential Heating Degree Hours	10.00%	Energy	1.57%
2.	Residential Cooling Degree Hours	10.00%	Energy	2.53%
3.	Electric Price	10.00%	Energy	-2.36%

Model: Commercial Energy

Line No.	Input Variable	Percent Change (Input)	Output Variable Affected	Percent Change (Output)
4.	Commercial Heating Degree Hours	10.00%	Energy	0.30%
5.	Commercial Cooling Degree Hours	10.00%	Energy	2.10%
6.	Electric Price	10.00%	Energy	-2.15%

Model: Commercial Rate GS Energy

Line No.	Input Variable	Percent Change (Input)	Output Variable Affected	Percent Change (Output)
7.	Commercial Heating Degree Hours	10.00%	Energy	0.54%
8.	Commercial Cooling Degree Hours	10.00%	Energy	2.50%
9.	Electric Price	10.00%	Energy	-3.50%

Model: Industrial Machine Billed Rate GSD Energy

Line No.	Input Variable	Percent Change (Input)	Output Variable Affected	Percent Change (Output)
10.	Commercial Heating Degree Hours	10.00%	Energy	0.28%
11.	Commercial Cooling Degree Hours	10.00%	Energy	1.42%

Model: Industrial Machine Billed Rate LP Energy

Line No.	Input Variable	Percent Change (Input)	Output Variable Affected	Percent Change (Output)
12.	Commercial Cooling Degree Hours	10.00%	Energy	0.73%

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1981 Through 1984
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1981	DEC	26.3654	6.7334	214.8486	10.0435	0	0	0	0	0	0	0	
1982	JAN	35.0674	6.7246	363.3564	2.1980	1	0	0	0	0	0	0	
1982	FEB	33.8512	6.7311	358.1741	2.0128	0	1	0	0	0	0	0	
1982	MAR	27.5438	6.7443	244.2058	6.2626	0	0	0	0	0	0	0	
1982	APR	25.5721	6.7739	125.8298	21.2723	0	0	0	0	0	0	0	
1982	MAY	23.3380	6.7878	56.4992	34.2058	0	0	0	0	0	0	0	
1982	JUN	34.7460	6.8008	8.8456	148.5070	0	0	1	0	0	0	0	
1982	JUL	44.7080	6.8417	0.0000	234.8658	0	0	0	1	0	0	0	
1982	AUG	43.8389	6.8877	0.0000	212.9046	0	0	0	0	1	0	0	
1982	SEP	42.1698	6.9310	0.0000	214.5710	0	0	0	0	0	1	0	
1982	OCT	33.3231	6.9048	17.5388	145.3360	0	0	0	0	0	0	1	
1982	NOV	25.2765	6.9290	100.2864	50.5820	0	0	0	0	0	0	0	
1982	DEC	24.9711	6.9588	142.4620	10.4218	0	0	0	0	0	0	0	
1983	JAN	32.1086	6.9919	281.8390	2.5212	1	0	0	0	0	0	0	32.0500
1983	FEB	36.6406	7.0172	414.8937	0.0000	0	1	0	0	0	0	0	37.5161
1983	MAR	30.0093	7.0268	280.1135	1.4635	0	0	0	0	0	0	0	29.2106
1983	APR	28.2164	7.0169	238.5900	2.3485	0	0	0	0	0	0	0	28.2847
1983	MAY	22.5604	7.0151	99.9790	20.7964	0	0	0	0	0	0	0	22.5834
1983	JUN	29.2866	7.0196	9.6141	99.4875	0	0	1	0	0	0	0	28.4581
1983	JUL	40.1827	7.0195	0.5242	177.1076	0	0	0	1	0	0	0	37.0379
1983	AUG	45.2447	7.0150	0.0000	275.0713	0	0	0	0	1	0	0	47.4423
1983	SEP	45.5696	7.0094	0.0994	259.9826	0	0	0	0	0	1	0	43.2985
1983	OCT	30.6317	6.9977	18.1622	129.8394	0	0	0	0	0	0	1	31.6129
1983	NOV	23.5463	6.9865	64.5606	47.0889	0	0	0	0	0	0	0	22.6538
1983	DEC	26.3812	6.9627	184.4933	10.1088	0	0	0	0	0	0	0	26.3061
1984	JAN	41.1104	6.9289	429.7543	1.3125	1	0	0	0	0	0	0	39.9746
1984	FEB	38.0509	6.8949	394.1461	0.2360	0	1	0	0	0	0	0	37.0628
1984	MAR	30.0912	6.8621	285.2399	2.0081	0	0	0	0	0	0	0	29.9056
1984	APR	24.1725	6.8384	133.0226	10.6187	0	0	0	0	0	0	0	23.5964
1984	MAY	24.3838	6.8021	45.7439	62.8979	0	0	0	0	0	0	0	23.9823
1984	JUN	32.2861	6.7648	13.7598	143.7566	0	0	1	0	0	0	0	33.4847
1984	JUL	43.1626	6.7302	2.9158	245.3822	0	0	0	1	0	0	0	43.9931
1984	AUG	42.4075	6.7014	0.0000	226.2591	0	0	0	0	1	0	0	41.1198
1984	SEP	38.0038	6.6733	0.0000	224.7063	0	0	0	0	0	1	0	41.2162
1984	OCT	32.0289	6.6651	11.6667	163.4000	0	0	0	0	0	0	1	33.4188
1984	NOV	28.9121	6.6480	32.8784	120.3160	0	0	0	0	0	0	0	28.1956
1984	DEC	27.9246	6.6427	200.0149	15.4770	0	0	0	0	0	0	0	27.9287

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1985 Through 1987
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1985	JAN	29.7284	6.6632	206.0214	9.0342	1	0	0	0	0	0	0	29.6293
1985	FEB	41.4895	6.6680	445.2472	1.6517	0	1	0	0	0	0	0	40.6663
1985	MAR	27.5765	6.6838	183.7754	7.3619	0	0	0	0	0	0	0	26.4520
1985	APR	23.2903	6.6643	76.2058	24.4036	0	0	0	0	0	0	0	22.6063
1985	MAY	24.7404	6.6405	22.0891	79.9157	0	0	0	0	0	0	0	24.8663
1985	JUN	34.7412	6.6100	1.9953	185.3364	0	0	1	0	0	0	0	36.4644
1985	JUL	41.0434	6.5834	0.1308	236.7897	0	0	0	1	0	0	0	42.0677
1985	AUG	44.0029	6.5542	0.0000	250.5598	0	0	0	0	1	0	0	43.8813
1985	SEP	41.7511	6.5230	0.2519	261.9175	0	0	0	0	0	1	0	43.3402
1985	OCT	33.7037	6.4964	10.6842	159.0574	0	0	0	0	0	0	1	33.1480
1985	NOV	28.5380	6.4734	32.8444	95.8104	0	0	0	0	0	0	0	26.8474
1985	DEC	26.2992	6.4520	107.5023	35.4434	0	0	0	0	0	0	0	25.6963
1986	JAN	36.2939	6.4071	359.0646	4.0112	1	0	0	0	0	0	0	37.9855
1986	FEB	32.4694	6.3819	300.1009	0.8028	0	1	0	0	0	0	0	33.1132
1986	MAR	26.6922	6.3479	200.1297	4.4927	0	0	0	0	0	0	0	27.4764
1986	APR	25.0572	6.3419	114.1997	26.4938	0	0	0	0	0	0	0	25.5235
1986	MAY	25.0239	6.3457	47.4871	65.3710	0	0	0	0	0	0	0	25.0377
1986	JUN	36.5910	6.3469	2.6698	183.2696	0	0	1	0	0	0	0	36.5125
1986	JUL	47.7365	6.3432	0.0000	290.5209	0	0	0	1	0	0	0	47.7644
1986	AUG	51.2245	6.3412	0.0000	317.3558	0	0	0	0	1	0	0	50.8145
1986	SEP	42.0541	6.3461	0.1966	224.9064	0	0	0	0	0	1	0	40.4769
1986	OCT	38.0182	6.3221	9.1975	202.0888	0	0	0	0	0	0	1	38.9887
1986	NOV	25.8623	6.3120	63.3744	52.8914	0	0	0	0	0	0	0	25.0688
1986	DEC	27.4586	6.2905	148.9678	24.5974	0	0	0	0	0	0	0	27.1910
1987	JAN	36.4038	6.2726	355.0416	1.1449	1	0	0	0	0	0	0	37.1701
1987	FEB	35.0896	6.2513	306.8786	0.9854	0	1	0	0	0	0	0	33.5098
1987	MAR	30.8250	6.2241	224.2149	2.8498	0	0	0	0	0	0	0	29.5593
1987	APR	26.6205	6.1872	146.1151	20.7958	0	0	0	0	0	0	0	26.9652
1987	MAY	26.9845	6.1440	30.0435	95.7194	0	0	0	0	0	0	0	27.4246
1987	JUN	38.0717	6.1027	0.1306	192.1680	0	0	1	0	0	0	0	38.0434
1987	JUL	46.6770	6.0649	0.0000	271.3043	0	0	0	1	0	0	0	46.8508
1987	AUG	48.9787	6.0266	0.0000	302.5894	0	0	0	0	1	0	0	50.2177
1987	SEP	45.3806	5.9837	0.0661	278.8205	0	0	0	0	0	1	0	46.7169
1987	OCT	31.3181	5.9502	33.3333	146.3667	0	0	0	0	0	0	1	34.8485
1987	NOV	24.0663	5.9097	109.3225	35.7034	0	0	0	0	0	0	0	25.5515
1987	DEC	28.2506	5.8638	182.9668	5.5507	0	0	0	0	0	0	0	27.0579

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1988 Through 1990
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1988	JAN	35.2283	5.8234	281.4842	3.8209	1	0	0	0	0	0	0	34.5851
1988	FEB	39.4005	5.7320	369.8918	0.6107	0	1	0	0	0	0	0	38.9361
1988	MAR	33.0136	5.6426	254.1712	1.4927	0	0	0	0	0	0	0	32.3281
1988	APR	26.0830	5.5532	113.5495	22.4303	0	0	0	0	0	0	0	26.6076
1988	MAY	26.3570	5.4672	35.1588	84.3744	0	0	0	0	0	0	0	27.9389
1988	JUN	34.0772	5.3833	4.8837	157.7767	0	0	1	0	0	0	0	36.3887
1988	JUL	46.2098	5.2956	0.0980	253.8289	0	0	0	1	0	0	0	46.1733
1988	AUG	46.0405	5.2078	0.0000	253.1917	0	0	0	0	1	0	0	46.8532
1988	SEP	43.9054	5.1204	0.3604	231.1639	0	0	0	0	0	1	0	43.6382
1988	OCT	34.4199	5.1031	23.3558	145.6202	0	0	0	0	0	0	1	35.7346
1988	NOV	24.4598	5.0872	68.8502	35.0000	0	0	0	0	0	0	0	25.1031
1988	DEC	29.5252	5.0721	201.1498	15.7885	0	0	0	0	0	0	0	31.2383
1989	JAN	31.2278	5.0635	200.8144	4.7137	1	0	0	0	0	0	0	31.7744
1989	FEB	30.4142	5.1065	215.6565	7.4855	0	1	0	0	0	0	0	32.1876
1989	MAR	32.8339	5.1381	233.1442	11.4360	0	0	0	0	0	0	0	32.2783
1989	APR	26.5578	5.1602	105.7828	25.6969	0	0	0	0	0	0	0	26.9902
1989	MAY	27.7094	5.1772	41.7618	75.1507	0	0	0	0	0	0	0	27.6595
1989	JUN	40.0857	5.1896	6.5139	185.8241	0	0	1	0	0	0	0	39.3155
1989	JUL	45.8901	5.2090	0.0000	233.0373	0	0	0	1	0	0	0	45.3429
1989	AUG	48.5013	5.2297	0.0337	260.4471	0	0	0	0	1	0	0	47.9203
1989	SEP	47.6111	5.2487	0.4266	267.6516	0	0	0	0	0	1	0	47.6015
1989	OCT	33.7338	5.2230	19.2135	123.2380	0	0	0	0	0	0	1	33.7078
1989	NOV	27.0650	5.1932	109.4352	41.3952	0	0	0	0	0	0	0	28.2444
1989	DEC	34.3927	5.1586	276.1111	9.4267	0	0	0	0	0	0	0	33.7464
1990	JAN	41.8712	5.1162	375.5100	0.3000	1	0	0	0	0	0	0	40.8165
1990	FEB	30.3598	5.0852	187.9789	2.3144	0	1	0	0	0	0	0	30.2257
1990	MAR	27.0715	5.0667	142.2690	8.4749	0	0	0	0	0	0	0	27.8290
1990	APR	25.8172	5.0882	97.4441	22.1912	0	0	0	0	0	0	0	26.1419
1990	MAY	28.3327	5.1079	29.5016	82.0355	0	0	0	0	0	0	0	28.1142
1990	JUN	41.4175	5.1261	3.3209	195.8047	0	0	1	0	0	0	0	41.0259
1990	JUL	49.7455	5.1442	0.0000	279.5625	0	0	0	1	0	0	0	50.1260
1990	AUG	51.2620	5.1598	0.0000	300.2496	0	0	0	0	1	0	0	51.9766
1990	SEP	49.0335	5.1660	1.2537	295.1284	0	0	0	0	0	1	0	50.0716
1990	OCT	38.1846	5.1721	18.3666	173.5370	0	0	0	0	0	0	1	38.5259
1990	NOV	27.2114	5.1824	116.8521	44.5374	0	0	0	0	0	0	0	28.7287
1990	DEC	28.7670	5.2054	193.6667	13.4400	0	0	0	0	0	0	0	29.9037

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules: | Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1991 Through 1993
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1991	JAN	33.1121	5.2310	228.3147	6.5776	1	0	0	0	0	0	0	33.2360
1991	FEB	34.1652	5.2433	246.3841	0.5105	0	1	0	0	0	0	0	32.7469
1991	MAR	28.7191	5.2569	165.8558	6.9773	0	0	0	0	0	0	0	28.5163
1991	APR	27.7978	5.2749	69.7512	43.9338	0	0	0	0	0	0	0	26.6075
1991	MAY	31.6787	5.2904	5.6995	100.2843	0	0	0	0	0	0	0	28.8376
1991	JUN	42.0768	5.2711	0.0000	199.3696	0	0	1	0	0	0	0	41.9333
1991	JUL	48.0357	5.2525	0.0000	254.4533	0	0	0	1	0	0	0	47.5749
1991	AUG	49.3368	5.2337	0.0000	277.0112	0	0	0	0	1	0	0	49.6565
1991	SEP	44.4099	5.2275	0.3443	244.6766	0	0	0	0	0	1	0	45.0105
1991	OCT	35.0716	5.2124	31.9888	138.5730	0	0	0	0	0	0	1	35.9943
1991	NOV	30.8063	5.1879	154.8622	51.0535	0	0	0	0	0	0	0	31.0783
1991	DEC	32.6812	5.1625	236.6409	7.0204	0	0	0	0	0	0	0	31.6233
1992	JAN	37.7148	5.1325	314.2457	0.6638	1	0	0	0	0	0	0	37.9025
1992	FEB	36.8211	5.1048	296.2464	0.6126	0	1	0	0	0	0	0	36.2596
1992	MAR	28.6042	5.0779	158.0258	10.2456	0	0	0	0	0	0	0	28.8756
1992	APR	28.0503	5.0294	117.0827	25.4587	0	0	0	0	0	0	0	28.2322
1992	MAY	28.0379	4.9885	51.1790	76.0742	0	0	0	0	0	0	0	30.0702
1992	JUN	38.1123	4.9458	7.3810	167.4121	0	0	1	0	0	0	0	38.6689
1992	JUL	50.9710	4.8979	0.0652	289.3370	0	0	0	1	0	0	0	51.1824
1992	AUG	48.9589	4.8550	0.0000	255.0435	0	0	0	0	1	0	0	48.1549
1992	SEP	43.3684	4.8121	0.3778	214.3448	0	0	0	0	0	1	0	43.4091
1992	OCT	33.6317	4.8137	16.7464	109.6555	0	0	0	0	0	0	1	33.4967
1992	NOV	27.5997	4.8187	89.1734	39.9919	0	0	0	0	0	0	0	28.0482
1992	DEC	32.4394	4.8175	237.3886	6.1441	0	0	0	0	0	0	0	32.9971
1993	JAN	31.6605	4.8372	185.3939	3.3333	1	0	0	0	0	0	0	31.6128
1993	FEB	34.4643	4.8517	261.8565	1.8968	0	1	0	0	0	0	0	34.9762
1993	MAR	34.2853	4.8555	254.7569	3.8120	0	0	0	0	0	0	0	33.4582
1993	APR	28.2355	4.8509	140.2609	15.8266	0	0	0	0	0	0	0	28.9076
1993	MAY	26.3782	4.8507	42.7488	49.4538	0	0	0	0	0	0	0	26.1821
1993	JUN	38.7540	4.8464	6.5116	174.6744	0	0	1	0	0	0	0	39.6258
1993	JUL	50.5261	4.8431	0.0327	271.0404	0	0	0	1	0	0	0	49.3926
1993	AUG	53.7626	4.8367	0.0000	302.4607	0	0	0	0	1	0	0	53.2923
1993	SEP	47.7456	4.8287	0.0940	265.1015	0	0	0	0	0	1	0	48.3662
1993	OCT	38.1936	4.7974	15.5481	158.7452	0	0	0	0	0	0	1	38.2098
1993	NOV	30.5820	4.7653	125.4589	47.0048	0	0	0	0	0	0	0	30.7818
1993	DEC	32.3969	4.7404	231.4009	9.4670	0	0	0	0	0	0	0	32.9518

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
_XX_Historical Years Ended 1994 Through 1996
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1994	JAN	44.2554	4.6954	400.0831	0.4814	1	0	0	0	0	0	0	43.0443
1994	FEB	38.9237	4.6678	320.4117	3.0632	0	1	0	0	0	0	0	38.6463
1994	MAR	29.7786	4.6531	171.4716	8.7812	0	0	0	0	0	0	0	30.4814
1994	APR	27.8054	4.6501	94.5170	26.8882	0	0	0	0	0	0	0	27.4683
1994	MAY	31.8209	4.6356	13.2399	95.3679	0	0	0	0	0	0	0	29.8582
1994	JUN	40.8156	4.6292	3.9537	177.0741	0	0	1	0	0	0	0	40.7482
1994	JUL	46.7140	4.6269	0.0000	230.7707	0	0	0	1	0	0	0	46.8809
1994	AUG	46.7807	4.6259	0.0000	217.9341	0	0	0	0	1	0	0	45.6883
1994	SEP	45.2307	4.6239	0.1966	214.0952	0	0	0	0	0	1	0	44.0884
1994	OCT	36.4131	4.6457	7.2019	123.7115	0	0	0	0	0	0	1	35.3984
1994	NOV	27.5066	4.6717	48.2560	44.4010	0	0	0	0	0	0	0	27.2119
1994	DEC	29.2685	4.6964	145.4581	18.5022	0	0	0	0	0	0	0	29.5777
1995	JAN	35.6611	4.7303	278.7410	0.9669	1	0	0	0	0	0	0	37.0354
1995	FEB	37.5113	4.7480	299.9952	1.5581	0	1	0	0	0	0	0	36.7212
1995	MAR	30.8962	4.7617	177.4279	5.6499	0	0	0	0	0	0	0	29.9217
1995	APR	27.4889	4.7673	85.4976	27.7391	0	0	0	0	0	0	0	27.4248
1995	MAY	30.4766	4.7743	28.3517	95.3679	0	0	0	0	0	0	0	30.9963
1995	JUN	45.2204	4.7759	1.9769	215.5417	0	0	1	0	0	0	0	43.5680
1995	JUL	48.5055	4.7796	0.8211	269.3684	0	0	0	1	0	0	0	50.3090
1995	AUG	52.2917	4.7823	0.0000	291.5628	0	0	0	0	1	0	0	51.9286
1995	SEP	51.1789	4.7850	0.1641	300.3328	0	0	0	0	0	1	0	51.9199
1995	OCT	39.5391	4.7781	9.8090	170.6292	0	0	0	0	0	0	1	39.3735
1995	NOV	28.7116	4.7714	101.0688	48.1824	0	0	0	0	0	0	0	29.9574
1995	DEC	32.3790	4.7640	229.3200	8.6178	0	0	0	0	0	0	0	32.4702
1996	JAN	44.0856	4.7463	389.1600	1.1400	1	0	0	0	0	0	0	42.1985
1996	FEB	42.9485	4.7316	385.1815	1.1232	0	1	0	0	0	0	0	42.1928
1996	MAR	34.8338	4.7160	257.5818	7.5900	0	0	0	0	0	0	0	35.0965
1996	APR	30.3098	4.7001	197.6451	6.5348	0	0	0	0	0	0	0	31.3469
1996	MAY	30.2221	4.6900	36.0726	85.6935	0	0	0	0	0	0	0	29.7861
1996	JUN	44.0519	4.6810	1.4326	228.9163	0	0	1	0	0	0	0	45.4977
1996	JUL	51.4053	4.6705	0.0000	307.0141	0	0	0	1	0	0	0	52.7472
1996	AUG	51.2292	4.6614	0.0000	294.6234	0	0	0	0	1	0	0	52.0890
1996	SEP	47.1778	4.6524	0.1921	245.1814	0	0	0	0	0	1	0	46.1833
1996	OCT	37.2567	4.6488	20.9662	136.9727	0	0	0	0	0	0	1	37.2188
1996	NOV	29.3667	4.6415	88.1729	59.3360	0	0	0	0	0	0	0	30.2408
1996	DEC	31.6318	4.6357	195.5258	14.4742	0	0	0	0	0	0	0	31.5862

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 1999
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
1997	JAN	37.5815	4.6308	268.0571	7.0999	1	0	0	0	0	0	0	37.3571
1997	FEB	33.9749	4.6256	281.1460	2.4159	0	1	0	0	0	0	0	36.7959
1997	MAR	29.7405	4.6234	119.9417	21.9870	0	0	0	0	0	0	0	27.9587
1997	APR	27.5224	4.6119	62.3874	34.9206	0	0	0	0	0	0	0	26.9296
1997	MAY	27.8116	4.6015	40.5121	62.9324	0	0	0	0	0	0	0	28.6747
1997	JUN	38.2054	4.5926	3.0652	156.6848	0	0	1	0	0	0	0	38.1111
1997	JUL	49.4567	4.5792	0.0327	267.7418	0	0	0	1	0	0	0	49.4600
1997	AUG	50.7660	4.5643	0.0000	267.8565	0	0	0	0	1	0	0	49.9022
1997	SEP	50.7068	4.5485	0.0000	263.9405	0	0	0	0	0	1	0	49.0772
1997	OCT	43.8383	4.5199	16.6775	170.7909	0	0	0	0	0	0	1	40.8476
1997	NOV	31.8171	4.4944	153.0531	30.8406	0	0	0	0	0	0	0	32.3693
1997	DEC	34.3105	4.4682	263.1831	2.7005	0	0	0	0	0	0	0	34.9181
1998	JAN	37.5127	4.4519	292.3493	0.7336	1	0	0	0	0	0	0	38.1464
1998	FEB	36.8882	4.4364	302.8171	0.1357	0	1	0	0	0	0	0	36.8629
1998	MAR	32.6755	4.4135	231.6467	2.4165	0	0	0	0	0	0	0	33.4850
1998	APR	29.2266	4.3750	101.7326	18.6175	0	0	0	0	0	0	0	27.8862
1998	MAY	32.3346	4.3307	27.7971	96.4444	0	0	0	0	0	0	0	31.6261
1998	JUN	51.1614	4.2841	0.4441	271.8897	0	0	1	0	0	0	0	50.1255
1998	JUL	56.5933	4.2442	0.0000	331.5756	0	0	0	1	0	0	0	57.0373
1998	AUG	53.0646	4.2081	0.0000	283.1777	0	0	0	0	1	0	0	52.6288
1998	SEP	47.4048	4.1737	0.0000	254.5881	0	0	0	0	0	1	0	49.3335
1998	OCT	45.4311	4.1393	8.2788	165.4423	0	0	0	0	0	0	1	40.5331
1998	NOV	30.3110	4.1057	62.8986	57.6570	0	0	0	0	0	0	0	31.5736
1998	DEC	29.3602	4.0799	103.7253	21.1593	0	0	0	0	0	0	0	28.8731
1999	JAN	38.0885	4.0492	311.5814	3.8765	1	0	0	0	0	0	0	40.3594
1999	FEB	30.8962	4.0266	159.3629	5.2839	0	1	0	0	0	0	0	30.6760
1999	MAR	30.5747	3.9999	194.2415	4.8331	0	0	0	0	0	0	0	32.1699
1999	APR	29.8360	3.9933	85.6830	36.8804	0	0	0	0	0	0	0	29.5142
1999	MAY	33.8707	3.9877	25.0032	92.6511	0	0	0	0	0	0	0	31.8977
1999	JUN	43.5515	3.9867	1.0015	171.4739	0	0	1	0	0	0	0	42.1141
1999	JUL	51.8889	3.9879	0.0000	250.7361	0	0	0	1	0	0	0	50.3584
1999	AUG	56.0028	3.9826	0.0000	306.0337	0	0	0	0	1	0	0	55.9579
1999	SEP	50.9584	3.9781	1.1156	260.7281	0	0	0	0	0	1	0	49.6290
1999	OCT	38.2917	3.9784	17.9663	129.6067	0	0	0	0	0	0	1	39.5137
1999	NOV	29.9760	3.9703	107.4528	40.1184	0	0	0	0	0	0	0	31.0238
1999	DEC	31.9853	3.9558	201.9279	7.0000	0	0	0	0	0	0	0	32.8756

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 2000 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

HISTORICAL		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
2000	JAN	36.3076	3.9619	277.0665	2.3974	1	0	0	0	0	0	0	37.6087
2000	FEB	39.9969	3.9635	312.7808	4.1735	0	1	0	0	0	0	0	39.0649
2000	MAR	28.4342	3.9607	121.8136	12.4571	0	0	0	0	0	0	0	29.0449
2000	APR	28.6324	3.9693	80.6842	26.6603	0	0	0	0	0	0	0	28.4286
2000	MAY	33.3212	3.9727	31.5328	86.5594	0	0	0	0	0	0	0	32.1186
2000	JUN	48.6553	3.9745	0.3261	223.8261	0	0	1	0	0	0	0	47.0916
2000	JUL	56.2215	3.9769	0.0000	312.2283	0	0	0	1	0	0	0	56.7195
2000	AUG	55.2847	3.9807	0.0000	310.0394	0	0	0	0	1	0	0	55.7888
2000	SEP	51.0811	3.9833	0.9269	259.2237	0	0	0	0	0	1	0	49.7639
2000	OCT	37.2765	3.9886	41.2921	117.8764	0	0	0	0	0	0	1	38.2863
2000	NOV	31.9720	3.9928	98.4197	58.8267	0	0	0	0	0	0	0	31.8085
2000	DEC	37.9863	3.9939	326.2784	5.5598	0	0	0	0	0	0	0	39.2239
2001	JAN	51.0355	3.9691	478.3640	0.5219	1	0	0	0	0	0	0	48.1090
2001	FEB	38.3336	3.9558	294.6520	1.6814	0	1	0	0	0	0	0	39.3861
2001	MAR	30.1080	3.9372	153.7731	8.5770	0	0	0	0	0	0	0	30.4575

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2001, 5/31/02
____Historical Years Ended 1981 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: RESIDENTIAL ENERGY

PROJECTED		ResSales (INPUT)	ResPrice (INPUT)	ResHDHBD (INPUT)	ResCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	ResSales (OUTPUT)
2001	APR		3.9220	79.2198	28.7802	0	0	0	0	0	0	0	28.6625
2001	MAY		3.9130	14.4105	85.4976	0	0	0	0	0	0	0	31.0939
2001	JUN		3.9035	0.7512	202.8476	0	0	1	0	0	0	0	44.9829
2001	JUL		3.8932	0.0000	254.1760	0	0	0	1	0	0	0	50.4998
2001	AUG		3.8835	0.0000	289.5807	0	0	0	0	1	0	0	53.7764
2001	SEP		3.8737	0.1271	230.8411	0	0	0	0	0	1	0	47.5331
2001	OCT		3.8606	12.5323	126.1355	0	0	0	0	0	0	1	37.1700
2001	NOV		3.8523	103.2029	29.4532	0	0	0	0	0	0	0	30.1692
2001	DEC		3.8479	236.6107	6.1557	0	0	0	0	0	0	0	34.7632
2002	JAN		3.8785	362.9199	0.9970	1	0	0	0	0	0	0	43.7291
2002	FEB		3.9040	321.9776	1.6438	0	1	0	0	0	0	0	40.0656
2002	MAR		3.9266	233.3748	5.5977	0	0	0	0	0	0	0	34.5890
2002	APR		3.9444	79.6434	28.3177	0	0	0	0	0	0	0	28.6699
2002	MAY		3.9619	14.0218	86.4243	0	0	0	0	0	0	0	30.7308
2002	JUN		3.9784	0.9005	202.2496	0	0	1	0	0	0	0	44.2764
2002	JUL		3.9944	0.0000	255.3587	0	0	0	1	0	0	0	50.2576
2002	AUG		4.0103	0.0000	288.6588	0	0	0	0	1	0	0	53.4513
2002	SEP		4.0261	0.1900	229.8914	0	0	0	0	0	1	0	46.8105
2002	OCT		4.0424	13.4781	123.8898	0	0	0	0	0	0	1	36.6894
2002	NOV		4.0591	102.8696	29.2512	0	0	0	0	0	0	0	29.7319
2002	DEC		4.0755	237.4202	6.2304	0	0	0	0	0	0	0	34.5977
2003	JAN		4.0876	365.1200	0.9022	1	0	0	0	0	0	0	42.9829
2003	FEB		4.0998	319.9866	1.6856	0	1	0	0	0	0	0	39.5490
2003	MAR		4.1123	239.1893	5.2330	0	0	0	0	0	0	0	34.5750
2003	APR		4.1247	83.7277	27.0583	0	0	0	0	0	0	0	28.3788
2003	MAY		4.1370	14.7426	83.9017	0	0	0	0	0	0	0	30.0498

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ResSales	Monthly Residential kWh per Customer per Average Billing Day
ResPrice	Residential Twelve Month Rolling Average of Real Price
ResHDHBD	Residential Heating Degree Hours per Average Billing Day (Base 65)
ResCDHBD	Residential Cooling Degree Hours per Average Billing Day (Base 70)
Jan through Oct	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1981 Through 1984
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1981	DEC	131.0285	6.6386	76.1919	58.0255	0	0	0	1	
1982	JAN	137.3067	6.6137	169.0099	22.4257	1	0	0	0	
1982	FEB	141.3006	6.6107	162.5655	17.7460	0	0	0	0	
1982	MAR	134.4411	6.6054	78.8947	38.4603	0	0	0	0	
1982	APR	143.7943	6.6039	36.3160	99.4182	0	0	0	0	
1982	MAY	145.0454	6.6060	6.9773	139.5802	0	1	0	0	
1982	JUN	188.0693	6.5961	0.0000	312.5429	0	0	0	0	
1982	JUL	202.6556	6.6088	0.0000	426.0281	0	0	0	0	
1982	AUG	198.9724	6.6286	0.0000	404.9094	0	0	0	0	
1982	SEP	191.1535	6.6463	0.0000	406.5521	0	0	0	0	
1982	OCT	176.0320	6.6496	0.6969	310.3740	0	0	0	0	
1982	NOV	144.1889	6.6518	24.1858	149.5681	0	0	1	0	
1982	DEC	135.5213	6.6586	40.9046	77.6468	0	0	0	1	
1983	JAN	138.4340	6.6538	112.5636	35.8008	1	0	0	0	132.5019
1983	FEB	147.1151	6.6487	180.4783	3.5507	0	0	0	0	141.6852
1983	MAR	133.5920	6.6555	89.4457	15.9968	0	0	0	0	130.4285
1983	APR	134.9977	6.6495	71.5089	26.6840	0	0	0	0	129.9672
1983	MAY	134.0438	6.6476	16.9968	102.0145	0	1	0	0	132.9156
1983	JUN	171.1932	6.6423	0.2953	266.5359	0	0	0	0	165.6282
1983	JUL	192.0773	6.6273	0.0000	365.4197	0	0	0	0	183.9152
1983	AUG	193.8601	6.6105	0.0000	467.0668	0	0	0	0	204.4169
1983	SEP	203.0473	6.5919	0.0000	451.5331	0	0	0	0	194.4935
1983	OCT	164.8941	6.5726	0.5008	285.7536	0	0	0	0	168.6424
1983	NOV	139.6802	6.5532	9.3635	155.0065	0	0	1	0	139.4250
1983	DEC	128.7938	6.5370	54.6125	62.1863	0	0	0	1	127.8250
1984	JAN	145.9428	6.5055	211.5511	12.9162	1	0	0	0	143.7907
1984	FEB	144.8935	6.4750	170.4944	5.8989	0	0	0	0	142.0759
1984	MAR	132.2195	6.4395	88.9011	22.2253	0	0	0	0	133.2318
1984	APR	130.4058	6.4036	31.3813	69.6155	0	0	0	0	133.2709
1984	MAY	148.5502	6.3566	4.2545	189.5786	0	1	0	0	146.8785
1984	JUN	181.1684	6.3126	0.4259	310.4462	0	0	0	0	175.4731
1984	JUL	193.8099	6.2938	0.0983	432.7441	0	0	0	0	200.6671
1984	AUG	192.0452	6.2700	0.0000	418.2639	0	0	0	0	190.9996
1984	SEP	180.7538	6.2466	0.0000	416.1732	0	0	0	0	194.8817
1984	OCT	170.1142	6.2317	0.6667	335.8333	0	0	0	0	174.1765
1984	NOV	162.6488	6.2081	6.8412	274.5656	0	0	1	0	162.5873
1984	DEC	132.3026	6.2065	66.3076	69.3655	0	0	0	1	132.6652

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1985 Through 1987
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1985	JAN	134.8974	6.2126	84.3889	63.4487	1	0	0	0	136.0783
1985	FEB	152.8591	6.2214	226.2809	15.4045	0	0	0	0	153.3844
1985	MAR	136.3521	6.2149	61.5412	56.6559	0	0	0	0	135.7887
1985	APR	139.2611	6.1744	7.2496	114.2577	0	0	0	0	138.7822
1985	MAY	157.1069	6.1349	1.7699	228.3452	0	1	0	0	156.7885
1985	JUN	186.7691	6.1104	0.0000	365.3411	0	0	0	0	187.5860
1985	JUL	193.4444	6.0729	0.0000	427.8505	0	0	0	0	197.1213
1985	AUG	199.1472	6.0419	0.0000	442.4737	0	0	0	0	199.3749
1985	SEP	193.3997	6.0054	0.0000	452.9955	0	0	0	0	200.1285
1985	OCT	179.7555	5.9732	0.5024	330.5407	0	0	0	0	176.7603
1985	NOV	163.0846	5.9411	5.3776	244.5802	0	0	1	0	162.2473
1985	DEC	147.0664	5.8959	37.1855	142.9457	0	0	0	1	146.2730
1986	JAN	145.9352	5.8542	162.0421	26.6629	1	0	0	0	144.8933
1986	FEB	140.7662	5.8118	115.8532	20.9358	0	0	0	0	142.6775
1986	MAR	144.3170	5.7781	71.7131	50.0324	0	0	0	0	141.1066
1986	APR	147.7004	5.7732	28.2492	107.1130	0	0	0	0	146.6116
1986	MAY	159.1639	5.7715	3.5903	190.0500	0	1	0	0	154.5794
1986	JUN	189.7763	5.7741	0.0000	364.7488	0	0	0	0	191.5633
1986	JUL	212.9057	5.7678	0.0000	482.5299	0	0	0	0	210.8189
1986	AUG	221.6387	5.7618	0.0000	509.3510	0	0	0	0	217.1660
1986	SEP	202.7254	5.7666	0.0000	411.7441	0	0	0	0	198.0144
1986	OCT	192.9765	5.7379	0.6753	382.3093	0	0	0	0	195.2536
1986	NOV	156.3624	5.7269	5.7180	170.0421	0	0	1	0	151.3045
1986	DEC	148.6680	5.7001	35.7584	94.0234	0	0	0	1	140.8663
1987	JAN	145.2040	5.6835	138.1234	10.6356	1	0	0	0	143.0997
1987	FEB	149.6247	5.6621	114.1748	18.5874	0	0	0	0	144.6291
1987	MAR	146.7709	5.6335	49.4637	26.6995	0	0	0	0	138.2115
1987	APR	145.0384	5.6059	45.3695	89.5478	0	0	0	0	150.7965
1987	MAY	166.0475	5.5678	5.8597	243.5323	0	1	0	0	167.0545
1987	JUN	199.4683	5.5234	0.0000	381.8538	0	0	0	0	195.4403
1987	JUL	214.0474	5.4885	0.0000	463.1413	0	0	0	0	212.9583
1987	AUG	219.7438	5.4525	0.0000	494.5652	0	0	0	0	219.6734
1987	SEP	212.3699	5.4101	0.0000	470.4331	0	0	0	0	215.1034
1987	OCT	176.6491	5.3817	3.1667	294.6000	0	0	0	0	180.9531
1987	NOV	147.1543	5.3403	21.0000	119.2950	0	0	1	0	148.3440
1987	DEC	142.5256	5.3008	56.6476	54.3040	0	0	0	1	140.9137

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1988 Through 1990
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1988	JAN	149.6748	5.2568	117.6361	42.9928	1	0	0	0	149.8215
1988	FEB	157.8684	5.1686	174.8869	21.5089	0	0	0	0	160.4897
1988	MAR	150.5299	5.0854	87.5961	26.0889	0	0	0	0	149.5193
1988	APR	146.9575	4.9860	27.5341	101.4241	0	0	0	0	153.8430
1988	MAY	168.6839	4.8989	2.2804	217.5900	0	1	0	0	167.2192
1988	JUN	186.3536	4.8202	0.0000	331.1163	0	0	0	0	195.6929
1988	JUL	216.3193	4.7342	0.0000	444.0047	0	0	0	0	214.8750
1988	AUG	211.0141	4.6490	0.0000	445.1871	0	0	0	0	218.5230
1988	SEP	211.1841	4.5640	0.0000	418.9516	0	0	0	0	211.8992
1988	OCT	184.1547	4.5500	0.8077	302.2788	0	0	0	0	191.0536
1988	NOV	157.8905	4.5257	7.4058	137.5314	0	0	1	0	157.4097
1988	DEC	148.1794	4.5161	66.3304	74.9648	0	0	0	1	154.6923
1989	JAN	145.6844	4.4987	67.7137	52.8777	1	0	0	0	150.1720
1989	FEB	149.9944	4.5319	70.0113	52.7032	0	0	0	0	154.6779
1989	MAR	156.0797	4.5616	91.7601	64.0211	0	0	0	0	160.5167
1989	APR	156.9574	4.5840	22.5997	117.8314	0	0	0	0	157.8602
1989	MAY	168.3290	4.6051	5.6499	206.5284	0	1	0	0	170.4422
1989	JUN	203.3576	4.6192	0.1944	365.2315	0	0	0	0	201.1753
1989	JUL	212.1755	4.6399	0.0000	424.2627	0	0	0	0	214.9786
1989	AUG	219.3466	4.6660	0.0000	451.6010	0	0	0	0	217.2006
1989	SEP	219.6388	4.6858	0.0000	456.8813	0	0	0	0	220.0187
1989	OCT	185.3627	4.6513	4.3483	277.8202	0	0	0	0	185.9503
1989	NOV	158.4809	4.6276	26.9136	133.0560	0	0	1	0	160.3999
1989	DEC	150.8868	4.5949	114.5511	54.6933	0	0	0	1	155.0960
1990	JAN	158.5133	4.5624	161.3500	14.8500	1	0	0	0	158.3522
1990	FEB	150.2597	4.5230	52.3128	40.9789	0	0	0	0	150.3532
1990	MAR	149.7332	4.4870	29.7812	64.9741	0	0	0	0	152.4086
1990	APR	157.4915	4.4984	18.7877	105.9530	0	0	0	0	157.8816
1990	MAY	173.4380	4.5110	3.1839	221.3468	0	1	0	0	174.0140
1990	JUN	210.6002	4.5225	0.0000	375.0372	0	0	0	0	206.5890
1990	JUL	225.5412	4.5391	0.0000	470.9250	0	0	0	0	225.3908
1990	AUG	228.7654	4.5482	0.0000	492.0384	0	0	0	0	228.9979
1990	SEP	222.8951	4.5572	0.0000	485.2567	0	0	0	0	227.1617
1990	OCT	202.7554	4.5371	0.0000	340.1190	0	0	0	0	198.4508
1990	NOV	160.7541	4.5168	20.4658	133.0779	0	0	1	0	161.8674
1990	DEC	148.8576	4.4994	60.2000	71.6800	0	0	0	1	151.9573

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1991 Through 1993
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1991	JAN	152.3413	4.4861	73.9526	48.6078	1	0	0	0	150.8425
1991	FEB	156.1402	4.4726	82.7407	26.1394	0	0	0	0	154.4394
1991	MAR	150.2552	4.4581	46.6969	55.8525	0	0	0	0	154.7470
1991	APR	167.3574	4.4454	13.4346	159.2811	0	0	0	0	167.8803
1991	MAY	193.7622	4.4234	0.0679	269.2682	0	1	0	0	183.7909
1991	JUN	206.5079	4.4261	0.0000	389.7717	0	0	0	0	214.7296
1991	JUL	221.5821	4.4240	0.0000	446.1682	0	0	0	0	220.0921
1991	AUG	221.6705	4.4286	0.0000	468.9775	0	0	0	0	225.7746
1991	SEP	212.6651	4.4308	0.0000	435.0849	0	0	0	0	217.1687
1991	OCT	194.6064	4.4162	4.0787	287.2247	0	0	0	0	191.2247
1991	NOV	169.2182	4.4006	62.0810	151.5267	0	0	1	0	172.9596
1991	DEC	150.5616	4.3881	92.0321	57.3285	0	0	0	1	154.8362
1992	JAN	155.0396	4.3694	114.2026	16.1724	1	0	0	0	152.1564
1992	FEB	157.2083	4.3496	106.9400	16.6434	0	0	0	0	158.7882
1992	MAR	153.3105	4.3281	41.8643	62.5250	0	0	0	0	155.7707
1992	APR	158.7427	4.2946	23.9611	98.5332	0	0	0	0	160.2850
1992	MAY	172.3345	4.2707	6.2323	198.9581	0	1	0	0	175.5514
1992	JUN	206.7611	4.2228	0.4572	342.7605	0	0	0	0	202.5401
1992	JUL	227.9542	4.1785	0.0000	481.0109	0	0	0	0	232.0719
1992	AUG	214.9828	4.1498	0.0000	447.0193	0	0	0	0	223.2277
1992	SEP	210.6417	4.1123	0.0000	403.1559	0	0	0	0	212.9983
1992	OCT	187.8392	4.1201	0.6699	261.5120	0	0	0	0	189.6484
1992	NOV	166.6651	4.1227	19.8768	138.3549	0	0	1	0	165.4299
1992	DEC	149.4444	4.1257	76.7860	44.4760	0	0	0	1	154.0649
1993	JAN	148.6505	4.1365	38.7879	35.5152	1	0	0	0	147.8464
1993	FEB	153.7660	4.1480	81.6290	22.1516	0	0	0	0	157.4275
1993	MAR	153.4298	4.1640	80.3241	25.6288	0	0	0	0	156.0204
1993	APR	156.6867	4.1587	29.7131	74.1637	0	0	0	0	157.8091
1993	MAY	160.5406	4.1612	4.7990	171.1653	0	1	0	0	169.1106
1993	JUN	199.2355	4.1647	0.0651	350.6186	0	0	0	0	204.4075
1993	JUL	228.0228	4.1652	0.0000	462.8491	0	0	0	0	224.6652
1993	AUG	230.2132	4.1476	0.0000	494.4607	0	0	0	0	232.0886
1993	SEP	220.8804	4.1426	0.0000	456.7970	0	0	0	0	225.0738
1993	OCT	199.6703	4.1143	0.5048	320.2163	0	0	0	0	199.7581
1993	NOV	167.1013	4.0885	40.4444	144.6667	0	0	1	0	171.3303
1993	DEC	151.2155	4.0614	72.8987	52.2687	0	0	0	1	154.2781

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1994 Through 1996
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1994	JAN	161.6240	4.0312	176.9054	9.8381	1	0	0	0	164.7262
1994	FEB	162.4147	4.0092	143.1540	31.6191	0	0	0	0	168.2303
1994	MAR	155.1909	3.9855	48.5689	60.2771	0	0	0	0	158.7189
1994	APR	161.7683	3.9794	19.5024	121.9157	0	0	0	0	166.7976
1994	MAY	185.7156	3.9641	0.8849	252.7828	0	1	0	0	183.1369
1994	JUN	206.6522	3.9583	0.0000	357.2917	0	0	0	0	209.1511
1994	JUL	218.8781	3.9567	0.0000	422.6864	0	0	0	0	222.2351
1994	AUG	222.4654	3.9482	0.0000	408.7572	0	0	0	0	218.3262
1994	SEP	212.9182	3.9528	0.0000	404.5694	0	0	0	0	219.1615
1994	OCT	197.9875	3.9709	0.0000	288.4135	0	0	0	0	195.4638
1994	NOV	170.0656	3.9853	3.4493	152.6473	0	0	1	0	168.3791
1994	DEC	159.0641	3.9967	34.4141	79.5903	0	0	0	1	156.5393
1995	JAN	152.4224	4.0206	91.7957	18.0388	1	0	0	0	155.1168
1995	FEB	162.1003	4.0311	115.2290	22.3887	0	0	0	0	162.0443
1995	MAR	163.9441	4.0376	54.1848	50.6451	0	0	0	0	158.7679
1995	APR	171.1559	4.0373	11.8444	116.1297	0	0	0	0	166.2663
1995	MAY	180.5416	4.0437	1.6337	237.8412	0	1	0	0	185.4047
1995	JUN	227.4341	4.0415	0.0000	398.8380	0	0	0	0	215.6724
1995	JUL	224.9114	4.0434	0.0000	458.1158	0	0	0	0	231.0489
1995	AUG	238.4954	4.0485	0.0000	483.5676	0	0	0	0	232.8062
1995	SEP	235.5013	4.0449	0.0000	491.3344	0	0	0	0	234.7855
1995	OCT	208.5759	4.0381	0.6742	341.7640	0	0	0	0	207.6733
1995	NOV	170.2913	4.0357	23.6208	148.0080	0	0	1	0	171.4046
1995	DEC	158.9704	4.0342	69.2889	59.9200	0	0	0	1	161.4971
1996	JAN	176.3552	4.0116	196.4400	21.9300	1	0	0	0	170.2307
1996	FEB	173.6914	4.0055	187.1280	16.4052	0	0	0	0	175.4981
1996	MAR	166.0643	4.0027	116.5381	55.0016	0	0	0	0	171.7266
1996	APR	165.2133	3.9939	68.4457	53.7763	0	0	0	0	162.9243
1996	MAY	181.8249	3.9829	4.7081	229.4758	0	1	0	0	182.8446
1996	JUN	218.3295	3.9728	0.0651	416.5163	0	0	0	0	223.5099
1996	JUL	237.0071	3.9576	0.0000	498.7746	0	0	0	0	234.6942
1996	AUG	227.7388	3.9494	0.0000	486.6422	0	0	0	0	236.3566
1996	SEP	227.4259	3.9338	0.0000	435.8760	0	0	0	0	223.2255
1996	OCT	209.9788	3.9240	1.7894	289.5096	0	0	0	0	199.5333
1996	NOV	172.6681	3.9182	19.6090	166.7787	0	0	1	0	178.4146
1996	DEC	162.4286	3.9084	64.2062	73.1753	0	0	0	1	160.3244

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 1999
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
1997	JAN	166.9740	3.9073	122.6148	49.1697	1	0	0	0	168.4418
1997	FEB	152.6955	3.8937	111.2257	31.6549	0	0	0	0	166.7135
1997	MAR	167.8026	3.8769	28.5219	107.2464	0	0	0	0	163.5520
1997	APR	175.4520	3.8543	5.5478	139.7504	0	0	0	0	172.3092
1997	MAY	175.0850	3.8390	2.2995	187.5797	0	1	0	0	177.5742
1997	JUN	209.5156	3.8291	0.0326	336.0326	0	0	0	0	207.1075
1997	JUL	232.5059	3.8202	0.0000	459.3546	0	0	0	0	232.0700
1997	AUG	228.9326	3.8061	0.0000	459.4446	0	0	0	0	230.4377
1997	SEP	239.9234	3.7927	0.0000	454.8933	0	0	0	0	231.0124
1997	OCT	226.3147	3.7721	1.9060	338.9271	0	0	0	0	214.9697
1997	NOV	171.5345	3.7490	33.1063	94.3478	0	0	1	0	169.5023
1997	DEC	172.7986	3.7162	100.2027	31.4523	0	0	0	1	163.7264
1998	JAN	157.3613	3.7012	110.2576	15.8341	1	0	0	0	164.9154
1998	FEB	165.7711	3.6820	96.1454	6.9208	0	0	0	0	158.4663
1998	MAR	166.9408	3.6597	73.6872	28.6921	0	0	0	0	165.4827
1998	APR	175.5944	3.6266	26.2075	108.1653	0	0	0	0	173.8402
1998	MAY	191.2713	3.5863	2.4348	244.7295	0	1	0	0	191.2710
1998	JUN	240.6544	3.5458	0.0000	460.1284	0	0	0	0	235.5769
1998	JUL	252.5012	3.5150	0.0000	523.2366	0	0	0	0	249.1361
1998	AUG	241.5894	3.4819	0.0000	475.1632	0	0	0	0	239.6252
1998	SEP	227.6626	3.4513	0.0000	446.6022	0	0	0	0	236.7228
1998	OCT	233.8360	3.4197	0.2692	341.5865	0	0	0	0	215.5170
1998	NOV	186.6443	3.3796	8.5217	169.8261	0	0	1	0	186.8811
1998	DEC	167.8268	3.3533	18.7375	104.5539	0	0	0	1	171.4016
1999	JAN	168.7121	3.3234	138.5145	34.0029	1	0	0	0	172.1950
1999	FEB	169.3430	3.2910	50.8065	61.7129	0	0	0	0	170.5035
1999	MAR	165.6835	3.2657	52.1426	43.4635	0	0	0	0	168.1661
1999	APR	174.2400	3.2604	14.4130	133.2065	0	0	0	0	179.2339
1999	MAY	197.9752	3.2572	1.5606	242.1616	0	1	0	0	192.4542
1999	JUN	219.1000	3.2559	0.0000	356.1863	0	0	0	0	221.5058
1999	JUL	240.5634	3.2492	0.0000	442.6204	0	0	0	0	236.1626
1999	AUG	248.0896	3.2454	0.0000	498.0337	0	0	0	0	247.7404
1999	SEP	241.6896	3.2450	0.0000	449.5641	0	0	0	0	235.9668
1999	OCT	206.6812	3.2457	1.6854	288.5056	0	0	0	0	213.0249
1999	NOV	181.8662	3.2399	21.6384	127.6464	0	0	1	0	176.3443
1999	DEC	168.3616	3.2355	58.7117	47.4234	0	0	0	1	165.5911

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 2000 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

HISTORICAL		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
2000	JAN	164.6253	3.2397	104.8786	31.5910	1	0	0	0	169.4572
2000	FEB	179.9325	3.2438	136.2350	33.1230	0	0	0	0	177.7088
2000	MAR	173.5881	3.2454	26.4117	81.4133	0	0	0	0	171.5562
2000	APR	181.8875	3.2505	13.2967	116.7560	0	0	0	0	175.9667
2000	MAY	195.7770	3.2544	2.5266	224.8313	0	1	0	0	194.0213
2000	JUN	237.5330	3.2599	0.0000	411.5543	0	0	0	0	230.6460
2000	JUL	249.2494	3.2634	0.0000	503.8696	0	0	0	0	250.3703
2000	AUG	255.0081	3.2653	0.0000	502.0157	0	0	0	0	247.2761
2000	SEP	244.8935	3.2646	0.0000	448.1598	0	0	0	0	239.9028
2000	OCT	206.9379	3.2705	6.9775	257.3596	0	0	0	0	203.8406
2000	NOV	188.7802	3.2783	28.3784	165.5628	0	0	1	0	186.9580
2000	DEC	175.5707	3.2884	128.0651	25.7655	0	0	0	1	171.9225
2001	JAN	190.1472	3.2738	251.3553	8.1360	1	0	0	0	186.9205
2001	FEB	178.9929	3.2631	115.6029	20.9657	0	0	0	0	175.2519
2001	MAR	174.7633	3.2507	38.4263	60.2431	0	0	0	0	171.5807

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2001, 5/31/02
____Historical Years Ended 1981 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL ENERGY

PROJECTED		ComSales (INPUT)	ComPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	May (INPUT)	Nov (INPUT)	Dec (INPUT)	ComSales (OUTPUT)
2001	APR		3.2416	13.6484	122.6703	0	0	0	0	180.3059
2001	MAY		3.2343	0.5325	239.1870	0	1	0	0	195.2903
2001	JUN		3.2239	0.0000	390.3779	0	0	0	0	227.8467
2001	JUL		3.2137	0.0000	445.1935	0	0	0	0	236.9338
2001	AUG		3.2038	0.0000	481.5712	0	0	0	0	245.1702
2001	SEP		3.1952	0.0000	421.1755	0	0	0	0	233.9462
2001	OCT		3.1793	0.3726	287.3952	0	0	0	0	208.4440
2001	NOV		3.1717	21.8986	113.5531	0	0	1	0	175.6819
2001	DEC		3.1584	73.4840	39.2427	0	0	0	1	167.0761
2002	JAN		3.1800	142.4199	9.8457	1	0	0	0	172.3735
2002	FEB		3.2051	124.4233	18.4169	0	0	0	0	176.3445
2002	MAR		3.2324	76.9774	39.0485	0	0	0	0	172.7195
2002	APR		3.2489	13.6143	121.5413	0	0	0	0	177.9060
2002	MAY		3.2650	0.4587	240.7629	0	1	0	0	194.0401
2002	JUN		3.2801	0.0000	389.4487	0	0	0	0	225.4884
2002	JUL		3.2949	0.0000	446.3804	0	0	0	0	235.6853
2002	AUG		3.3097	0.0000	480.6445	0	0	0	0	242.2042
2002	SEP		3.3243	0.0000	420.0000	0	0	0	0	230.6608
2002	OCT		3.3393	0.5446	284.1637	0	0	0	0	204.9635
2002	NOV		3.3550	21.7778	113.0483	0	0	1	0	172.5031
2002	DEC		3.3703	73.7530	39.4383	0	0	0	1	163.5740
2003	JAN		3.3801	144.1067	9.4578	1	0	0	0	169.4535
2003	FEB		3.3902	123.3311	18.7876	0	0	0	0	173.0516
2003	MAR		3.4002	79.3786	37.1068	0	0	0	0	169.7567
2003	APR		3.4098	14.9417	117.8655	0	0	0	0	174.9754
2003	MAY		3.4193	0.4587	236.6349	0	1	0	0	191.1120

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
ComSales	Monthly Commercial kWh per Customer per Average Billing Day
ComPrice	Commercial Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Dec	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 2000
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL RATE GS ENERGY

HISTORICAL		GSKwhCustDay (INPUT)	GSPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Mar (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	Nov (INPUT)	GSKwhCustDay (OUTPUT)
1997	DEC	21.9139	5.8157	100.2027	31.4523	0	0	0	0	0	0	0	0	0	22.3949
1998	JAN	24.4736	5.7771	110.2576	15.8341	1	0	0	0	0	0	0	0	0	24.5177
1998	FEB	23.9478	5.7824	96.1454	6.9208	0	1	0	0	0	0	0	0	0	23.3112
1998	MAR	21.8226	5.7388	73.6872	28.6921	0	0	1	0	0	0	0	0	0	22.1518
1998	APR	21.8876	5.7071	26.2075	108.1653	0	0	0	0	0	0	0	0	0	22.1481
1998	MAY	25.4770	5.6520	2.4348	244.7295	0	0	0	0	0	0	0	0	0	25.8095
1998	JUN	34.5589	5.5965	0.0000	460.1284	0	0	0	1	0	0	0	0	0	34.6660
1998	JUL	38.3421	5.5492	0.0000	523.2366	0	0	0	0	1	0	0	0	0	38.3242
1998	AUG	37.8179	5.4997	0.0000	475.1632	0	0	0	0	0	1	0	0	0	37.6075
1998	SEP	34.2690	5.4385	0.0000	446.6022	0	0	0	0	0	0	1	0	0	34.5330
1998	OCT	31.7862	5.4177	0.2692	341.5865	0	0	0	0	0	0	0	1	0	31.5697
1998	NOV	25.9861	5.3661	8.5217	169.8261	0	0	0	0	0	0	0	0	1	26.0780
1998	DEC	24.4286	5.3240	18.7375	104.5539	0	0	0	0	0	0	0	0	0	24.8119
1999	JAN	27.4687	5.3036	138.5145	34.0029	1	0	0	0	0	0	0	0	0	27.3757
1999	FEB	20.8489	5.2609	50.8065	61.7129	0	1	0	0	0	0	0	0	0	21.1595
1999	MAR	24.2607	5.2418	52.1426	43.4635	0	0	1	0	0	0	0	0	0	24.3271
1999	APR	25.2440	5.2110	14.4130	133.2065	0	0	0	0	0	0	0	0	0	24.7180
1999	MAY	28.0945	5.1983	1.5606	242.1616	0	0	0	0	0	0	0	0	0	28.1805
1999	JUN	32.6237	5.1947	0.0000	356.1863	0	0	0	1	0	0	0	0	0	32.5145
1999	JUL	37.2183	5.1796	0.0000	442.6204	0	0	0	0	1	0	0	0	0	36.2708
1999	AUG	38.6197	5.1964	0.0000	498.0337	0	0	0	0	0	1	0	0	0	37.9081
1999	SEP	36.4741	5.2011	0.0000	449.5641	0	0	0	0	0	0	1	0	0	36.3756
1999	OCT	29.8867	5.1686	1.8854	288.5056	0	0	0	0	0	0	0	1	0	29.2818
1999	NOV	26.7979	5.1437	21.6384	127.6464	0	0	0	0	0	0	0	0	1	26.0855
1999	DEC	24.3740	5.1314	58.7117	47.4234	0	0	0	0	0	0	0	0	0	24.4238
2000	JAN	25.5425	5.1384	104.8786	31.5910	1	0	0	0	0	0	0	0	0	25.5775
2000	FEB	28.7435	5.1132	136.2350	33.1230	0	1	0	0	0	0	0	0	0	28.5910
2000	MAR	23.6899	5.1141	26.4117	81.4133	0	0	1	0	0	0	0	0	0	23.4962
2000	APR	20.3286	5.1386	13.2967	116.7560	0	0	0	0	0	0	0	0	0	20.4100
2000	MAY	26.5524	5.1416	2.5266	224.8313	0	0	0	0	0	0	0	0	0	26.5449
2000	JUN	33.3658	5.1437	0.0000	411.5543	0	0	0	1	0	0	0	0	0	33.3825
2000	JUL	33.6072	5.1510	0.0000	503.8696	0	0	0	0	1	0	0	0	0	33.7934
2000	AUG	35.5157	5.1542	0.0000	502.0157	0	0	0	0	0	1	0	0	0	35.6625
2000	SEP	34.6294	5.1551	0.0000	448.1598	0	0	0	0	0	0	1	0	0	34.6392
2000	OCT	26.4485	5.1632	6.9775	257.3596	0	0	0	0	0	0	0	1	0	26.5713
2000	NOV	23.4465	5.1888	28.3784	165.5628	0	0	0	0	0	0	0	0	1	23.5829
2000	DEC	24.7038	5.1921	128.0651	25.7655	0	0	0	0	0	0	0	0	0	24.7598

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
GSKwhCustDay	Monthly Commercial Rate GS kWh per Customer per Average Billing Day
GSPrice	Commercial Rate GS Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Nov	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
___Projected Test Year Ended 5/31/03
___Prior Year Ended 5/31/02
_XX_Historical Years Ended 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL RATE GS ENERGY

HISTORICAL		GSKwhCustDay (INPUT)	GSPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Mar (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	Nov (INPUT)	GSKwhCustDay (OUTPUT)
2001	JAN	31.3036	5.1647	251.3553	8.1360	1	0	0	0	0	0	0	0	0	31.2995
2001	FEB	24.9774	5.1578	115.6029	20.9657	0	1	0	0	0	0	0	0	0	24.9995
2001	MAR	21.9107	5.1463	38.4263	60.2431	0	0	1	0	0	0	0	0	0	21.9450

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
GSKwhCustDay	Monthly Commercial Rate GS kWh per Customer per Average Billing Day
GSPrice	Commercial Rate GS Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Nov	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2001, 5/31/02
____Historical Years Ended 1997 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: COMMERCIAL RATE GS ENERGY

HISTORICAL		GSKwhCustDay (INPUT)	GSPrice (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Mar (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	Oct (INPUT)	Nov (INPUT)	GSKwhCustDay (OUTPUT)
2001	APR		5.1128	13.6484	122.6703	0	0	0	0	0	0	0	0	0	23.6470
2001	MAY		5.0999	0.5325	239.1870	0	0	0	0	0	0	0	0	0	26.5601
2001	JUN		5.0902	0.0000	390.3779	0	0	0	1	0	0	0	0	0	33.4011
2001	JUL		5.0772	0.0000	445.1935	0	0	0	0	1	0	0	0	0	37.5506
2001	AUG		5.0644	0.0000	481.5712	0	0	0	0	0	1	0	0	0	39.3653
2001	SEP		5.0537	0.0000	421.1755	0	0	0	0	0	0	1	0	0	34.4700
2001	OCT		5.0333	0.3726	287.3952	0	0	0	0	0	0	0	1	0	31.1126
2001	NOV		5.0136	21.8986	113.5531	0	0	0	0	0	0	0	0	1	26.0943
2001	DEC		5.0005	73.4840	39.2427	0	0	0	0	0	0	0	0	0	23.3942
2002	JAN		5.0388	142.4199	9.8457	1	0	0	0	0	0	0	0	0	27.0004
2002	FEB		5.0634	124.4233	18.4169	0	1	0	0	0	0	0	0	0	26.3070
2002	MAR		5.0882	76.9774	39.0485	0	0	1	0	0	0	0	0	0	24.0303
2002	APR		5.1143	13.6143	121.5413	0	0	0	0	0	0	0	0	0	23.2063
2002	MAY		5.1398	0.4587	240.7629	0	0	0	0	0	0	0	0	0	26.5703
2002	JUN		5.1645	0.0000	389.4487	0	0	0	1	0	0	0	0	0	33.1474
2002	JUL		5.1886	0.0000	446.3804	0	0	0	0	1	0	0	0	0	36.4656
2002	AUG		5.2122	0.0000	480.6445	0	0	0	0	0	1	0	0	0	38.3344
2002	SEP		5.2358	0.0000	420.0000	0	0	0	0	0	0	1	0	0	34.0374
2002	OCT		5.2599	0.5446	284.1637	0	0	0	0	0	0	0	1	0	29.9805
2002	NOV		5.2845	21.7778	113.0483	0	0	0	0	0	0	0	0	1	24.8904
2002	DEC		5.3087	73.7530	39.4383	0	0	0	0	0	0	0	0	0	22.5519
2003	JAN		5.3237	144.1067	9.4578	1	0	0	0	0	0	0	0	0	26.5351
2003	FEB		5.3388	123.3311	18.7876	0	1	0	0	0	0	0	0	0	25.6442
2003	MAR		5.3541	79.3786	37.1068	0	0	1	0	0	0	0	0	0	23.3902
2003	APR		5.3694	14.9417	117.8655	0	0	0	0	0	0	0	0	0	22.6544
2003	MAY		5.3843	0.4587	236.6349	0	0	0	0	0	0	0	0	0	25.9698

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
GSKwhCustDay	Monthly Commercial Rate GS kWh per Customer per Average Billing Day
GSPrice	Commercial Rate GS Twelve Month Rolling Average of Real Price
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Nov	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		____Projected Test Year Ended 5/31/03
DOCKET NO. 010949-EI		____Prior Year Ended 5/31/02
		_XX_Historical Years Ended 1994 Through 1996
		Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE GSD ENERGY

HISTORICAL		MBIndGSD (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	MBIndGSD (OUTPUT)
1994	JAN	957.5407	176.9054	9.8381	1	0	0	0	0	
1994	FEB	1025.9743	143.1540	31.6191	0	0	0	0	0	1008.7861
1994	MAR	1000.3232	48.5689	60.2771	0	0	0	0	0	965.1745
1994	APR	1009.1657	19.5024	121.9157	0	0	0	0	0	998.2597
1994	MAY	1078.7173	0.8849	252.7828	0	0	0	0	0	1067.5593
1994	JUN	1097.3465	0.0000	357.2917	0	1	0	0	0	1073.2666
1994	JUL	1075.7663	0.0000	422.6864	0	0	1	0	0	1084.6265
1994	AUG	1103.5415	0.0000	408.7572	0	0	0	1	0	1066.8814
1994	SEP	1143.6015	0.0000	404.5694	0	0	0	0	1	1119.8395
1994	OCT	1099.5719	0.0000	288.4135	0	0	0	0	0	1096.3200
1994	NOV	1030.5059	3.4493	152.6473	0	0	0	0	0	996.4361
1994	DEC	979.7517	34.4141	79.5903	0	0	0	0	0	979.9149
1995	JAN	809.6250	91.7957	18.0388	1	0	0	0	0	897.9531
1995	FEB	956.1645	115.2290	22.3887	0	0	0	0	0	933.6923
1995	MAR	938.5780	54.1848	50.6451	0	0	0	0	0	939.1632
1995	APR	954.0506	11.8444	116.1297	0	0	0	0	0	957.5960
1995	MAY	1059.9766	1.6337	237.8412	0	0	0	0	0	1033.8205
1995	JUN	1063.7521	0.0000	398.8380	0	1	0	0	0	1096.7641
1995	JUL	1049.9669	0.0000	458.1158	0	0	1	0	0	1076.1101
1995	AUG	1118.5717	0.0000	483.5676	0	0	0	1	0	1091.4977
1995	SEP	1075.8774	0.0000	491.3344	0	0	0	0	1	1159.9866
1995	OCT	1032.5213	0.6742	341.7640	0	0	0	0	0	1066.2435
1995	NOV	908.7826	23.6208	148.0080	0	0	0	0	0	952.9437
1995	DEC	896.9531	89.2889	59.9200	0	0	0	0	0	935.6839
1996	JAN	1041.8490	196.4400	21.9300	1	0	0	0	0	918.2574
1996	FEB	1087.4923	187.1280	16.4052	0	0	0	0	0	1062.6869
1996	MAR	921.4967	116.5381	55.0016	0	0	0	0	0	1031.5927
1996	APR	933.3093	68.4457	53.7763	0	0	0	0	0	921.5466
1996	MAY	1053.6400	4.7081	229.4758	0	0	0	0	0	1020.3859
1996	JUN	1102.5852	0.0651	416.5163	0	1	0	0	0	1107.3524
1996	JUL	1089.4410	0.0000	498.7746	0	0	1	0	0	1117.9117
1996	AUG	1123.3132	0.0000	486.6422	0	0	0	1	0	1099.8061
1996	SEP	1144.1531	0.0000	435.8780	0	0	0	0	1	1123.6108
1996	OCT	1151.4053	1.7894	289.5096	0	0	0	0	0	1087.3915
1996	NOV	968.2516	19.6090	166.7787	0	0	0	0	0	1043.9166
1996	DEC	908.1297	64.2062	73.1753	0	0	0	0	0	952.8748

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
MBIndGSD	Monthly Industrial Machine Billed GSD kWh per Customer per Average Billing Day
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Sep	Monthly Dummy Variables

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 1999
Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE GSD ENERGY

HISTORICAL		MBIndGSD (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	MBIndGSD (OUTPUT)
1997	JAN	854.5974	122.6148	49.1897	1	0	0	0	0	894.5219
1997	FEB	879.3805	111.2257	31.6549	0	0	0	0	0	938.0111
1997	MAR	933.0976	28.5219	107.2464	0	0	0	0	0	917.5282
1997	APR	960.0210	5.5478	139.7504	0	0	0	0	0	955.6477
1997	MAY	927.3665	2.2995	187.5797	0	0	0	0	0	997.1074
1997	JUN	990.4302	0.0326	336.0326	0	1	0	0	0	1001.8648
1997	JUL	1040.7131	0.0000	459.3546	0	0	1	0	0	1060.8296
1997	AUG	1007.6869	0.0000	459.4446	0	0	0	1	0	1069.7407
1997	SEP	1094.9678	0.0000	454.8933	0	0	0	0	1	1085.3417
1997	OCT	1047.3141	1.9060	338.9271	0	0	0	0	0	1088.3572
1997	NOV	911.2447	33.1063	94.3478	0	0	0	0	0	931.5509
1997	DEC	944.8751	100.2027	31.4523	0	0	0	0	0	941.1090
1998	JAN	952.1152	110.2576	15.8341	1	0	0	0	0	883.7072
1998	FEB	1009.7946	96.1454	6.9208	0	0	0	0	0	978.4515
1998	MAR	990.3309	73.6872	28.6921	0	0	0	0	0	979.7812
1998	APR	1041.7896	26.2075	108.1653	0	0	0	0	0	990.2798
1998	MAY	1046.1671	2.4348	244.7295	0	0	0	0	0	1062.7990
1998	JUN	1164.2073	0.0000	460.1284	0	1	0	0	0	1128.4480
1998	JUL	1165.5865	0.0000	523.2366	0	0	1	0	0	1151.4340
1998	AUG	1167.2662	0.0000	475.1632	0	0	0	1	0	1123.3651
1998	SEP	1151.7401	0.0000	446.6022	0	0	0	0	1	1158.2245
1998	OCT	1048.9366	0.2692	341.5865	0	0	0	0	0	1121.9214
1998	NOV	1016.6493	8.5217	169.8261	0	0	0	0	0	965.8568
1998	DEC	963.8923	18.7375	104.5539	0	0	0	0	0	970.2811
1999	JAN	933.7484	138.5145	34.0029	1	0	0	0	0	930.9089
1999	FEB	974.6402	50.8065	61.7129	0	0	0	0	0	956.3700
1999	MAR	1000.2833	52.1426	43.4635	0	0	0	0	0	953.3124
1999	APR	1056.5621	14.4130	133.2065	0	0	0	0	0	1006.9704
1999	MAY	1111.5842	1.5606	242.1616	0	0	0	0	0	1083.6785
1999	JUN	1087.9712	0.0000	356.1863	0	1	0	0	0	1093.4115
1999	JUL	1137.5152	0.0000	442.6204	0	0	1	0	0	1093.6556
1999	AUG	1115.6088	0.0000	498.0337	0	0	0	1	0	1153.0996
1999	SEP	1122.0992	0.0000	449.5641	0	0	0	0	1	1124.7757
1999	OCT	1105.2077	1.6854	288.5056	0	0	0	0	0	1070.0825
1999	NOV	966.1079	21.6384	127.6464	0	0	0	0	0	994.7485
1999	DEC	915.1072	58.7117	47.4234	0	0	0	0	0	943.5578

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
MBIndGSD	Monthly Industrial Machine Billed GSD kWh per Customer per Average Billing Day
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Sep	Monthly Dummy Variables

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 9/30/2000
Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE GSD ENERGY

HISTORICAL		MBIndGSD (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	MBIndGSD (OUTPUT)
2000	JAN	860.9763	104.8786	31.5910	1	0	0	0	0	884.8318
2000	FEB	999.8921	136.2350	33.1230	0	0	0	0	0	973.3329
2000	MAR	987.7752	26.4117	81.4133	0	0	0	0	0	952.0054
2000	APR	978.6629	13.2967	116.7560	0	0	0	0	0	984.4620
2000	MAY	1060.5410	2.5266	224.8313	0	0	0	0	0	1037.8080
2000	JUN	1101.3631	0.0000	411.5543	0	1	0	0	0	1110.0599
2000	JUL	1141.4655	0.0000	503.8696	0	0	1	0	0	1122.5447
2000	AUG	1091.6707	0.0000	502.0157	0	0	0	1	0	1135.8895
2000	SEP	1125.1741	0.0000	448.1598	0	0	0	0	1	1109.7612

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
MBIndGSD	Monthly Industrial Machine Billed GSD kWh per Customer per Average Billing Day
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Sep	Monthly Dummy Variables

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2000, 2001, 5/31/02
____Historical Years Ended 1994 Through 9/30/2000
Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE GSD ENERGY

PROJECTED		MBIndGSD (INPUT)	ComHDHBD (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Jun (INPUT)	Jul (INPUT)	Aug (INPUT)	Sep (INPUT)	MBIndGSD (OUTPUT)
2000	OCT		6.9775	257.3596	0	0	0	0	0	1054.7884
2000	NOV		28.3784	165.5628	0	0	0	0	0	1007.9988
2000	DEC		128.0651	25.7655	0	0	0	0	0	984.4467
2001	JAN		251.3553	8.1360	1	0	0	0	0	991.9886
2001	FEB		115.6029	20.9657	0	0	0	0	0	972.4117
2001	MAR		38.4263	60.2431	0	0	0	0	0	943.8721
2001	APR		13.6484	122.6703	0	0	0	0	0	968.6469
2001	MAY		0.5325	239.1870	0	0	0	0	0	1038.6152
2001	JUN		0.0000	390.3779	0	1	0	0	0	1079.6667
2001	JUL		0.0000	445.1935	0	0	1	0	0	1078.7430
2001	AUG		0.0000	481.5712	0	0	0	1	0	1109.9600
2001	SEP		0.0000	421.1755	0	0	0	0	1	1108.3748
2001	OCT		0.3726	287.3952	0	0	0	0	0	1071.3451
2001	NOV		21.8986	113.5531	0	0	0	0	0	968.3688
2001	DEC		73.4840	39.2427	0	0	0	0	0	954.7328
2002	JAN		142.4199	9.8457	1	0	0	0	0	915.1872
2002	FEB		124.4233	18.4169	0	0	0	0	0	977.0629
2002	MAR		76.9774	39.0485	0	0	0	0	0	957.1047
2002	APR		13.6143	121.5413	0	0	0	0	0	967.8715
2002	MAY		0.4587	240.7629	0	0	0	0	0	1039.6451
2002	JUN		0.0000	389.4487	0	1	0	0	0	1079.0388
2002	JUL		0.0000	446.3804	0	0	1	0	0	1079.5540
2002	AUG		0.0000	480.6445	0	0	0	1	0	1109.3302
2002	SEP		0.0000	420.0000	0	0	0	0	1	1107.5748
2002	OCT		0.5448	284.1637	0	0	0	0	0	1069.2678
2002	NOV		21.7778	113.0483	0	0	0	0	0	967.9386
2002	DEC		73.7530	39.4383	0	0	0	0	0	955.0589
2003	JAN		144.1067	9.4578	1	0	0	0	0	916.1322
2003	FEB		123.3311	18.7876	0	0	0	0	0	976.5325
2003	MAR		79.3786	37.1068	0	0	0	0	0	957.5035
2003	APR		14.9417	117.8655	0	0	0	0	0	966.3193
2003	MAY		0.4587	236.6349	0	0	0	0	0	1036.8335

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
MBIndGSD	Monthly Industrial Machine Billed GSD kWh per Customer per Average Billing Day
ComHDHBD	Commercial Heating Degree Hours per Average Billing Day (Base 54)
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Sep	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1998 Through 9/30/2000
Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE LP ENERGY

HISTORICAL		MBIndLP (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Mar (INPUT)	MBIndLP (OUTPUT)
1998	JAN	6773.5317	15.8341	1	0	0	
1998	FEB	6778.0447	6.9208	0	1	0	7036.2787
1998	MAR	6862.5118	28.6921	0	0	1	6948.7904
1998	APR	7501.5331	108.1653	0	0	0	7666.5239
1998	MAY	7855.3167	244.7295	0	0	0	7962.0480
1998	JUN	8483.4607	460.1284	0	0	0	8526.0440
1998	JUL	9432.7361	523.2366	0	0	0	8720.9856
1998	AUG	8753.5303	475.1632	0	0	0	8962.6942
1998	SEP	8875.3693	446.6022	0	0	0	8827.7722
1998	OCT	8421.3562	341.5865	0	0	0	8444.1351
1998	NOV	8752.5447	169.8261	0	0	0	7908.8074
1998	DEC	7987.8869	104.5539	0	0	0	8105.1193
1999	JAN	6614.9623	34.0029	1	0	0	6276.8235
1999	FEB	7016.5861	61.7129	0	1	0	7083.4025
1999	MAR	7125.2425	43.4635	0	0	1	7032.0239
1999	APR	8261.2235	133.2065	0	0	0	7837.6108
1999	MAY	8713.0238	242.1616	0	0	0	8281.3962
1999	JUN	8306.8761	356.1863	0	0	0	8658.9595
1999	JUL	9058.5490	442.6204	0	0	0	8554.4480
1999	AUG	8776.7350	498.0337	0	0	0	8946.6350
1999	SEP	9119.5646	449.5641	0	0	0	8618.1964
1999	OCT	7870.2452	288.5056	0	0	0	8415.6348
1999	NOV	7140.6384	127.6464	0	0	0	7604.4612
1999	DEC	7145.7035	47.4234	0	0	0	7249.3954
2000	JAN	5641.1295	31.5910	1	0	0	5945.2739
2000	FEB	6950.8617	33.1230	0	1	0	6553.4820
2000	MAR	7283.2441	81.4133	0	0	1	7136.2899
2000	APR	7890.5079	116.7560	0	0	0	7821.6914
2000	MAY	7649.4282	224.8313	0	0	0	8081.9126
2000	JUN	8347.2743	411.5543	0	0	0	8326.1155
2000	JUL	8370.9946	503.8696	0	0	0	8666.0855
2000	AUG	8192.5207	502.0157	0	0	0	8558.2390
2000	SEP	7712.6710	448.1598	0	0	0	8334.9970

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
MBIndLP	Monthly Industrial Machine Billed LP kWh per Customer per Average Billing Day
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Mar	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2000, 2001, 5/31/02
____Historical Years Ended 1998 Through 9/30/2000
Witness: R. L. McGee

FORECASTING MODEL: INDUSTRIAL MACHINE BILLED RATE LP ENERGY

PROJECTED		MBIndLP (INPUT)	ComCDHBD (INPUT)	Jan (INPUT)	Feb (INPUT)	Mar (INPUT)	MBIndLP (OUTPUT)
2000	OCT		257.3596	0	0	0	7674.2049
2000	NOV		165.5628	0	0	0	7650.5503
2000	DEC		25.7655	0	0	0	7385.2205
2001	JAN		8.1360	1	0	0	6022.9305
2001	FEB		20.9657	0	1	0	6729.9493
2001	MAR		60.2431	0	0	1	6991.9078
2001	APR		122.6703	0	0	0	7726.4411
2001	MAY		239.1670	0	0	0	8035.2472
2001	JUN		390.3779	0	0	0	8434.0082
2001	JUL		445.1935	0	0	0	8578.7010
2001	AUG		481.5712	0	0	0	8674.6242
2001	SEP		421.1755	0	0	0	8515.8879
2001	OCT		287.3952	0	0	0	8164.0770
2001	NOV		113.5531	0	0	0	7706.8684
2001	DEC		39.2427	0	0	0	7511.4316
2002	JAN		9.8457	1	0	0	6070.0868
2002	FEB		18.4169	0	1	0	6743.2958
2002	MAR		39.0485	0	0	1	6945.4859
2002	APR		121.5413	0	0	0	7727.9008
2002	MAY		240.7629	0	0	0	8041.4737
2002	JUN		389.4487	0	0	0	8432.5426
2002	JUL		446.3804	0	0	0	8582.2827
2002	AUG		480.6445	0	0	0	8672.4031
2002	SEP		420.0000	0	0	0	8512.8978
2002	OCT		284.1637	0	0	0	8155.6255
2002	NOV		113.0483	0	0	0	7705.5632
2002	DEC		39.4383	0	0	0	7511.9564
2003	JAN		9.4578	1	0	0	6069.0714
2003	FEB		18.7876	0	1	0	6744.2731
2003	MAR		37.1068	0	0	1	6940.3801
2003	APR		117.8655	0	0	0	7718.2332
2003	MAY		236.6349	0	0	0	8030.6169

VARIABLE	DESCRIPTION
MBIndLP	Monthly Industrial Machine Billed LP kWh per Customer per Average Billing Day
ComCDHBD	Commercial Cooling Degree Hours per Average Billing Day (Base 62)
Jan through Mar	Monthly Dummy Variables

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimatin and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 1999
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #1 ENERGY

HISTORICAL		KWHperDay (INPUT)	TimeTrend (INPUT)	ResHDHperDay (INPUT)	ComCDHperDay (INPUT)	KWHperDay (OUTPUT)
1997	JAN	775563.6452	12.0833	307.8710	35.6774	788046.9660
1997	FEB	720842.4643	12.1667	220.0357	46.7857	703995.7106
1997	MAR	660628.7742	12.2500	54.4194	149.0000	645072.0306
1997	APR	644310.4667	12.3333	69.7667	124.8667	633612.3362
1997	MAY	734797.9032	12.4167	13.3226	276.7742	759105.8993
1997	JUN	841087.7000	12.5000	0.4333	391.8667	868098.5665
1997	JUL	999940.0645	12.5833	0.0000	479.8065	997524.5415
1997	AUG	970870.8387	12.6667	0.0000	459.8065	973896.2135
1997	SEP	942336.3000	12.7500	0.0000	429.2667	937228.1445
1997	OCT	738362.5806	12.8333	65.3226	203.7742	732924.8183
1997	NOV	697889.3000	12.9167	209.9667	37.6333	691373.5273
1997	DEC	802606.8387	13.0000	360.0323	21.5161	841535.4211
1998	JAN	739074.8387	13.0833	282.8065	7.8387	738766.5986
1998	FEB	734538.2143	13.1667	255.3929	18.7143	722467.2868
1998	MAR	692693.5484	13.2500	204.0000	46.5806	700186.1784
1998	APR	639923.7667	13.3333	52.5667	149.4333	658023.6034
1998	MAY	884963.3871	13.4167	3.0968	382.3548	891600.5659
1998	JUN	1095789.5000	13.5000	0.0333	514.9333	1053291.4876
1998	JUL	1050670.5806	13.5833	0.0000	504.4839	1041441.4753
1998	AUG	1035163.6452	13.6667	0.0000	479.0323	1011068.4537
1998	SEP	920127.5000	13.7500	0.0000	393.1000	905869.2425
1998	OCT	775833.2258	13.8333	30.3548	240.1290	751912.3520
1998	NOV	664769.3333	13.9167	89.5333	112.9000	662261.0432
1998	DEC	719702.4516	14.0000	201.8710	69.7742	736523.2543
1999	JAN	777719.1935	14.0833	259.1613	45.4194	772020.8672
1999	FEB	712135.8571	14.1667	192.8214	49.5000	703480.6735
1999	MAR	665202.8710	14.2500	157.4839	49.8387	665222.1838
1999	APR	734444.6000	14.3333	30.6333	219.3000	733149.5517
1999	MAY	788127.5161	14.4167	8.3226	283.6452	788748.6284
1999	JUN	905058.5000	14.5000	0.0000	418.7000	947581.0310
1999	JUL	996724.1613	14.5833	0.0000	458.8065	998315.9432
1999	AUG	1089165.0968	14.6667	0.0000	511.8065	1065002.6543
1999	SEP	892360.2000	14.7500	6.2333	360.9333	886478.3665
1999	OCT	745003.9677	14.8333	52.8387	207.5806	750348.6844
1999	NOV	696432.8000	14.9167	149.9333	68.2667	688442.7180
1999	DEC	808704.7742	15.0000	300.6129	21.4194	801276.9502

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #1 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimatin and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 2000 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #1 ENERGY

		KWHperDay	TimeTrend	ResHDHperDay	ComCDHperDay	KWHperDay
HISTORICAL		(INPUT)	(INPUT)	(INPUT)	(INPUT)	(OUTPUT)
2000	JAN	819525.2581	15.0833	286.3871	36.6774	805250.1761
2000	FEB	754137.1724	15.1667	210.6207	52.2069	740259.3079
2000	MAR	662361.7419	15.2500	92.0000	102.4194	669920.4369
2000	APR	675311.5000	15.3333	71.9000	133.8667	687308.0400
2000	MAY	902326.6129	15.4167	1.9032	346.5484	872729.5037
2000	JUN	983074.2667	15.5000	0.0333	436.2000	982655.6528
2000	JUL	1067097.9355	15.5833	0.0000	541.0968	1113511.1182
2000	AUG	1055629.1613	15.6667	0.0000	497.1935	1060309.9029
2000	SEP	899379.3333	15.7500	6.4000	356.3333	894381.1827
2000	OCT	736028.3871	15.8333	55.3226	193.9032	749610.3537
2000	NOV	782451.8000	15.9167	224.6667	81.9333	802893.2418
2000	DEC	935334.4839	16.0000	426.0968	12.7742	945272.8187
2001	JAN	949616.0000	16.0833	408.8710	7.7742	920804.6710
2001	FEB	724674.7143	16.1667	201.1071	47.1786	736711.4703
2001	MAR	719832.6129	16.2500	179.3226	46.7419	712755.5398

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #1 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimatin and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2001, 5/31/02
____Historical Years Ended 1981 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #1 ENERGY

PROJECTED		KWHperDay (INPUT)	TimeTrend (INPUT)	ResHDHperDay (INPUT)	ComCDHperDay (INPUT)	KWHperDay (OUTPUT)
2001	APR		16.3333	33.1667	181.9000	716503.7455
2001	MAY		16.4167	3.9677	308.1935	840988.2306
2001	JUN		16.5000	0.0000	428.7667	986807.8740
2001	JUL		16.5833	0.0000	480.3548	1051747.8825
2001	AUG		16.6667	0.0000	459.4516	1027002.0904
2001	SEP		16.7500	1.3667	371.8333	921255.9278
2001	OCT		16.8333	44.7742	189.9355	746209.3444
2001	NOV		16.9167	169.5667	65.9667	734478.3979
2001	DEC		17.0000	309.6129	16.7419	832397.2790
2002	JAN		17.0833	360.9032	13.7742	887598.3398
2002	FEB		17.1667	285.4286	22.3929	814386.0042
2002	MAR		17.2500	173.0645	58.4194	733541.8673
2002	APR		17.3333	33.1667	181.9000	729889.9656
2002	MAY		17.4167	3.9677	308.1935	854374.4508
2002	JUN		17.5000	0.0000	428.7667	1000194.0942
2002	JUL		17.5833	0.0000	480.3548	1065134.1027
2002	AUG		17.6667	0.0000	459.4516	1040388.3106
2002	SEP		17.7500	1.3667	371.8333	934642.1480
2002	OCT		17.8333	44.7742	189.9355	759595.5646
2002	NOV		17.9167	169.5667	65.9667	747864.6181
2002	DEC		18.0000	309.6129	16.7419	845783.4991
2003	JAN		18.0833	360.9032	13.7742	900984.5600
2003	FEB		18.1667	285.4286	22.3929	827772.2244
2003	MAR		18.2500	173.0645	58.4194	746928.0875
2003	APR		18.3333	33.1667	181.9000	743276.1858
2003	MAY		18.4167	3.9677	308.1935	867760.6709

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #1 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 1997 Through 1999
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #2 ENERGY

HISTORICAL		KWHperDay (INPUT)	TimeTrend (INPUT)	ResHDHperDay (INPUT)	ComCDHperDay (INPUT)	Jun (INPUT)	Jul (INPUT)	KWHperDay (OUTPUT)
1997	JAN	91032.2581	12.0833	307.8710	35.6774	0	0	90421.4383
1997	FEB	87857.1429	12.1667	220.0357	46.7857	0	0	82967.5225
1997	MAR	83645.1613	12.2500	54.4194	149.0000	0	0	81727.6758
1997	APR	81533.3333	12.3333	69.7667	124.8667	0	0	79689.3347
1997	MAY	95619.0000	12.4167	13.3226	276.7742	0	0	98055.9276
1997	JUN	108546.3667	12.5000	0.4333	391.8667	1	0	112158.2768
1997	JUL	124804.7419	12.5833	0.0000	479.8065	0	1	125075.7956
1997	AUG	124894.6452	12.6667	0.0000	459.8065	0	0	126340.9340
1997	SEP	120958.8000	12.7500	0.0000	429.2667	0	0	121638.7718
1997	OCT	92137.6452	12.8333	65.3226	203.7742	0	0	92822.5731
1997	NOV	79807.3667	12.9167	209.9667	37.6333	0	0	81960.4071
1997	DEC	91603.3548	13.0000	360.0323	21.5161	0	0	95612.2907
1998	JAN	85489.7419	13.0833	282.8065	7.8387	0	0	85339.1114
1998	FEB	85019.4286	13.1667	255.3929	18.7143	0	0	84311.6219
1998	MAR	83501.9677	13.2500	204.0000	46.5806	0	0	83429.6042
1998	APR	81656.5667	13.3333	52.5667	149.4333	0	0	83808.8219
1998	MAY	112149.4839	13.4167	3.0968	382.3548	0	0	115846.0731
1998	JUN	136173.8000	13.5000	0.0333	514.9333	1	0	133789.1692
1998	JUL	130746.3548	13.5833	0.0000	504.4839	0	1	131052.9065
1998	AUG	131768.0000	13.6667	0.0000	479.0323	0	0	131448.3195
1998	SEP	116755.3000	13.7500	0.0000	393.1000	0	0	117909.0951
1998	OCT	98076.7742	13.8333	30.3548	240.1290	0	0	96922.0030
1998	NOV	82524.4000	13.9167	89.5333	112.9000	0	0	83125.0467
1998	DEC	86680.0323	14.0000	201.8710	69.7742	0	0	88432.1867
1999	JAN	90887.8710	14.0833	259.1613	45.4194	0	0	90845.3239
1999	FEB	86592.2857	14.1667	192.8214	49.5000	0	0	84569.6994
1999	MAR	83310.0000	14.2500	157.4839	49.8387	0	0	81013.5475
1999	APR	94579.6667	14.3333	30.6333	219.3000	0	0	94648.9201
1999	MAY	104644.3226	14.4167	8.3226	283.6452	0	0	102697.5960
1999	JUN	120889.5667	14.5000	0.0000	418.7000	1	0	120473.1650
1999	JUL	130560.4839	14.5833	0.0000	458.8065	0	1	125805.9277
1999	AUG	142688.8065	14.6667	0.0000	511.8065	0	0	138717.1527
1999	SEP	116389.7667	14.7500	6.2333	380.9333	0	0	115484.3654
1999	OCT	96208.1290	14.8333	52.8387	207.5806	0	0	96174.7622
1999	NOV	85105.0667	14.9167	149.9333	68.2667	0	0	84505.8729
1999	DEC	94202.2903	15.0000	300.6129	21.4194	0	0	93320.8954

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #2 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)
Jun, Jul	Monthly Dummy Variables

Supporting Schedules: Recap Schedules:

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
____Projected Test Year Ended 5/31/03
____Prior Year Ended 5/31/02
_XX_Historical Years Ended 2000 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #2 ENERGY

HISTORICAL		KWHperDay (INPUT)	TimeTrend (INPUT)	ResHDHperDay (INPUT)	ComCDHperDay (INPUT)	Jun (INPUT)	Jul (INPUT)	KWHperDay (OUTPUT)
2000	JAN	95391.8710	15.0833	286.3871	36.6774	0	0	94403.3200
2000	FEB	90982.6207	15.1667	210.6207	52.2069	0	0	88945.7935
2000	MAR	84280.3548	15.2500	92.0000	102.4194	0	0	84437.1327
2000	APR	85930.1000	15.3333	71.9000	133.8667	0	0	87473.9293
2000	MAY	115310.9677	15.4167	1.9032	346.5484	0	0	114086.3727
2000	JUN	126119.8667	15.5000	0.0333	436.2000	1	0	125308.7890
2000	JUL	136797.3871	15.5833	0.0000	541.0968	0	1	140974.3380
2000	AUG	138265.6129	15.6667	0.0000	497.1935	0	0	138426.0650
2000	SEP	119117.0000	15.7500	6.4000	356.3333	0	0	116808.5195
2000	OCT	92124.0000	15.8333	55.3226	193.9032	0	0	96298.6271
2000	NOV	93749.1667	15.9167	224.6667	81.9333	0	0	96720.9105
2000	DEC	105531.8387	16.0000	426.0968	12.7742	0	0	107405.3994
2001	JAN	107525.7097	16.0833	408.8710	7.7742	0	0	104935.0226
2001	FEB	87040.5000	16.1667	201.1071	47.1786	0	0	89166.0824
2001	MAR	87261.7742	16.2500	179.3226	46.7419	0	0	86936.0550

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EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #2 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)
Jun, Jul	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For each forecasting model used to estimate test year projections for customers, demand, and energy, provide the historical and projected values for the input variables and the output variables used in estimating and/or validating the model. Also, provide a description of each variable, specifying the unit of measurement and the time span or cross sectional range of the data.

Type of Data Shown:
_XX_Projected Test Year Ended 5/31/03
_XX_Prior Years Ended 2001, 5/31/02
____Historical Years Ended 1981 Through 3/31/2001
Witness: R. L. McGee

FORECASTING MODEL: WHOLESALE CUSTOMER #2 ENERGY

PROJECTED		KWHperDay (INPUT)	TimeTrend (INPUT)	ResHDHperDay (INPUT)	ComCDHperDay (INPUT)	Jun (INPUT)	Jul (INPUT)	KWHperDay (OUTPUT)
2001	APR		16.3333	33.1667	181.9000	0	0	93033.6722
2001	MAY		16.4167	3.9677	308.1935	0	0	110228.4548
2001	JUN		16.5000	0.0000	428.7667	1	0	126159.5312
2001	JUL		16.5833	0.0000	480.3548	0	1	133324.0351
2001	AUG		16.6667	0.0000	459.4516	0	0	134445.0770
2001	SEP		16.7500	1.3667	371.8333	0	0	120783.0704
2001	OCT		16.8333	44.7742	189.9355	0	0	96577.4155
2001	NOV		16.9167	169.5667	65.9667	0	0	90319.5760
2001	DEC		17.0000	309.6129	16.7419	0	0	97617.8244
2002	JAN		17.0833	360.9032	13.7742	0	0	102801.1167
2002	FEB		17.1667	285.4286	22.3929	0	0	96272.2806
2002	MAR		17.2500	173.0645	58.4194	0	0	90169.7543
2002	APR		17.3333	33.1667	181.9000	0	0	95073.8602
2002	MAY		17.4167	3.9677	308.1935	0	0	112268.6429
2002	JUN		17.5000	0.0000	428.7667	1	0	128199.7193
2002	JUL		17.5833	0.0000	480.3548	0	1	135364.2232
2002	AUG		17.6667	0.0000	459.4516	0	0	136485.2651
2002	SEP		17.7500	1.3667	371.8333	0	0	122823.2585
2002	OCT		17.8333	44.7742	189.9355	0	0	98617.6036
2002	NOV		17.9167	169.5667	65.9667	0	0	92359.7641
2002	DEC		18.0000	309.6129	16.7419	0	0	99658.0125
2003	JAN		18.0833	360.9032	13.7742	0	0	104841.3048
2003	FEB		18.1667	285.4286	22.3929	0	0	98312.4687
2003	MAR		18.2500	173.0645	58.4194	0	0	92209.9424
2003	APR		18.3333	33.1667	181.9000	0	0	97114.0483
2003	MAY		18.4167	3.9677	308.1935	0	0	114308.8310

EXPLANATION OF VARIABLES:

VARIABLE	DESCRIPTION
KWHperDay	Monthly Wholesale Customer #2 kWh per Day
TimeTrend	Monthly Time Trend Variable
ResHDHperDay	Residential Heating Degree Hours per Day (Base 65)
ComCDHperDay	Commercial Cooling Degree Hours per Day (Base 62)
Jun, Jul	Monthly Dummy Variables

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: Provide actual, projected (as applicable) and normal monthly heating degree days for the utility's service territory for the test year and the five previous years. Provide this information both by calendar month and by billing month. Provide a description of how the actual, projected and normal heating degree days for the utility's service territory are derived.

Type of Data Shown:
_X__Projected Test Year Ended 5/31/03
_X__Prior Years Ended 5/31/01, 5/31/02
_X__Historical Years Ended 1997 Through 3/31/01
Witness: R. L. McGee

PENSACOLA WEATHER STATION
RESIDENTIAL HEATING DEGREE DAYS (65 DEG. F BASE)

	HISTORICAL 1997		HISTORICAL 1998		HISTORICAL 1999		HISTORICAL 2000	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JAN	369.5	351.0	362.0	393.0	326.0	412.0	347.5	357.0
FEB	235.5	369.0	280.0	362.0	215.0	184.0	226.5	370.0
MAR	39.5	120.0	250.0	265.0	170.0	216.0	80.5	115.0
APR	45.5	39.0	45.0	106.0	24.0	83.0	59.0	73.0
MAY	3.5	22.0	0.0	20.0	1.0	16.0	0.0	16.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	2.5	0.0
OCT	55.0	10.0	10.5	2.0	41.0	8.0	39.0	30.0
NOV	243.5	161.0	72.5	44.0	126.5	88.0	267.0	97.0
DEC	450.0	328.0	233.0	96.0	370.0	224.0	525.0	410.0
ANNUAL	1,462.0	1,400.0	1,253.0	1,288.0	1,275.5	1,231.0	1,547.0	1,468.0

	PRIOR YEAR Ended 5/31/01		PRIOR YEAR Ended 5/31/02		NORMAL TEST YEAR ENDED 5/31/03	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JUN	0.0	0.0	0.0	0.0	0.0	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0
SEP	2.5	0.0	0.0	0.0	0.0	0.0
OCT	39.0	30.0	27.0	6.0	27.0	6.0
NOV	267.0	97.0	211.0	106.0	211.0	104.0
DEC	525.0	410.0	374.0	299.0	374.0	304.0
JAN	524.5	631.0	448.5	459.0	448.5	463.0
FEB	222.5	352.0	318.5	387.0	318.5	367.0
MAR	205.5	172.0	192.5	262.0	192.5	270.0
APR	11.5	66.0	11.5	64.0	11.5	69.0
MAY	0.0	2.0	0.0	2.0	0.0	2.0
ANNUAL	1,797.5	1,760.0	1,583.0	1,585.0	1,583.0	1,585.0

Actual heating degree days are based on hourly temperature observations recorded at the Pensacola, Florida weather station by the National Oceanic and Atmospheric Administration (NOAA). Daily Residential heating degree day values are calculated by subtracting the daily mid-range temperature (maximum plus minimum divided by two) from the 65 degree base. Calendar and billing month totals represent summations of daily values for calendar months and billing cycles, respectively. Normal values used in the forecast are based on 30-year climatological normals published by NOAA, which represents expected values based on observations from the data recorded during the period 1951-1980. Monthly weather data from the period 1980-1988 (for which hourly observations are readily available) are compared to the 30-year NOAA normals for the purpose of selecting months which compose the Typical Meterological Year.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: Provide actual, projected (as applicable) and normal monthly heating degree days for the utility's service territory for the test year and the five previous years. Provide this information both by calendar month and by billing month. Provide a description of how the actual, projected and normal heating degree days for the utility's service territory are derived.	Type of Data Shown: _X__Projected Test Year Ended 5/31/03 _X__Prior Years Ended 5/31/01, 5/31/02 _X__Historical Years Ended 1997 Through 3/31/01 Witness: R. L. McGee

PENSACOLA WEATHER STATION
COMMERCIAL HEATING DEGREE DAYS (54 DEG. F BASE)

	HISTORICAL 1997		HISTORICAL 1998		HISTORICAL 1999		HISTORICAL 2000	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JAN	152.5	138.0	89.5	123.0	134.0	163.0	133.0	108.0
FEB	47.0	119.0	58.0	87.0	45.0	38.0	54.5	140.0
MAR	0.0	16.0	74.0	65.0	6.5	32.0	3.0	9.0
APR	0.0	0.0	0.0	20.0	0.0	2.0	2.0	3.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JUN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OCT	2.0	0.0	0.0	0.0	0.0	0.0	1.5	1.0
NOV	31.5	16.0	4.5	3.0	8.0	4.0	62.0	20.0
DEC	185.5	93.0	62.5	14.0	104.5	43.0	229.5	128.0
ANNUAL	418.5	382.0	288.5	312.0	298.0	282.0	485.5	407.0

	PRIOR YEAR Ended 5/31/01		PRIOR YEAR Ended 5/31/02		NORMAL TEST YEAR ENDED 5/31/03	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JUN	0.0	0.0	0.0	0.0	0.0	0.0
JUL	0.0	0.0	0.0	0.0	0.0	0.0
AUG	0.0	0.0	0.0	0.0	0.0	0.0
SEP	0.0	0.0	0.0	0.0	0.0	0.0
OCT	1.5	1.0	0.0	0.0	0.0	0.0
NOV	62.0	20.0	40.0	14.0	40.0	14.0
DEC	229.5	128.0	95.0	62.0	95.0	63.0
JAN	226.5	303.0	162.5	149.0	162.5	152.0
FEB	55.0	113.0	87.0	127.0	87.0	120.0
MAR	17.0	19.0	33.5	63.0	33.5	66.0
APR	0.0	3.0	0.0	3.0	0.0	3.0
MAY	0.0	0.0	0.0	0.0	0.0	0.0
ANNUAL	591.5	587.0	418.0	418.0	418.0	418.0

Actual heating degree days are based on hourly temperature observations recorded at the Pensacola, Florida weather station by the National Oceanic and Atmospheric Administration (NOAA). Daily Commercial heating degree day values are calculated by subtracting the daily mid-range temperature (maximum plus minimum divided by two) from the 54 degree base. Calendar and billing month totals represent summations of daily values for calendar months and billing cycles, respectively. Normal values used in the forecast are based on 30-year climatological normals published by NOAA, which represents expected values based on observations from the data recorded during the period 1951-1980. Monthly weather data from the period 1980-1988 (for which hourly observations are readily available) are compared to the 30-year NOAA normals for the purpose of selecting months which compose the Typical Meterological Year.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: Provide actual, projected (as applicable) and normal monthly cooling degree days for the utility's service territory for the test year and the five previous years. Provide this information both by calendar month and by billing month. Provide a description of how the actual, projected and normal cooling degree days for the utility's service territory are derived.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		_XX_Projected Test Year Ended 5/31/03
		_XX_Prior Years Ended 5/31/01, 5/31/02
		_XX_Historical Years Ended 1997 Through 3/31/01
DOCKET NO. 010949-EI		Witness: R. L. McGee

PENSACOLA WEATHER STATION

RESIDENTIAL COOLING DEGREE DAYS (70 DEG. F BASE)

	HISTORICAL 1997		HISTORICAL 1998		HISTORICAL 1999		HISTORICAL 2000	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JAN	0.5	0.0	0.0	0.0	0.0	2.0	0.0	0.0
FEB	3.0	1.0	0.0	0.0	0.5	0.0	0.0	0.0
MAR	25.5	15.0	2.0	0.0	0.5	1.0	8.0	2.0
APR	14.0	21.0	27.0	15.0	95.5	42.0	15.5	12.0
MAY	138.5	56.0	254.5	109.0	129.5	100.0	206.0	81.0
JUN	264.0	202.0	426.0	367.0	299.5	234.0	310.5	289.0
JUL	396.5	364.0	430.5	456.0	359.5	333.0	469.5	410.0
AUG	371.0	362.0	392.5	372.0	435.5	403.0	414.0	408.0
SEP	326.5	373.0	268.5	341.0	234.5	345.0	231.5	359.0
OCT	97.0	217.0	105.5	209.0	87.5	153.0	59.5	127.0
NOV	0.0	27.0	15.5	48.0	0.0	31.0	27.5	48.0
DEC	0.0	0.0	10.0	13.0	0.0	0.0	0.0	5.0
ANNUAL	1,636.5	1,638.0	1,932.0	1,930.0	1,642.5	1,644.0	1,742.0	1,741.0

	PRIOR YEAR Ended 5/31/01		PRIOR YEAR Ended 5/31/02		NORMAL TEST YEAR ENDED 5/31/03	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JUN	310.5	289.0	310.0	256.0	310.0	260.0
JUL	469.5	410.0	392.0	345.0	392.0	346.0
AUG	414.0	408.0	368.0	382.0	368.0	382.0
SEP	231.5	359.0	248.5	324.0	248.5	323.0
OCT	59.5	127.0	71.0	154.0	71.0	151.0
NOV	27.5	48.0	1.0	23.0	1.0	22.0
DEC	0.0	5.0	1.5	1.0	1.5	1.0
JAN	0.0	0.0	0.0	0.0	0.0	0.0
FEB	0.0	0.0	0.0	0.0	0.0	0.0
MAR	3.5	4.0	2.5	1.0	2.5	1.0
APR	30.5	12.0	30.5	11.0	30.5	10.0
MAY	155.0	82.0	155.0	85.0	155.0	81.0
ANNUAL	1,701.5	1,744.0	1,580.0	1,582.0	1,580.0	1,577.0

Actual cooling degree days are based on hourly temperature observations recorded at the Pensacola, Florida weather station by the National Oceanic and Atmospheric Administration (NOAA). Daily Residential cooling degree day values are calculated by subtracting the the 70 degree base from the daily mid-range temperature (maximum plus minimum divided by two). Calendar and billing month totals represent summations of daily values for calendar months and billing cycles, respectively. Normal values used in the forecast are based on 30-year climatological normals published by NOAA, which represents expected values based on observations from the data recorded during the period 1951-1980. Monthly weather data from the period 1980-1988 (for which hourly observations are readily available) are compared to the 30-year NOAA normals for the purpose of selecting months which compose the Typical Meterological Year.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: Provide actual, projected (as applicable) and normal monthly cooling degree days for the utility's service territory for the test year and the five previous years. Provide this information both by calendar month and by billing month. Provide a description of how the actual, projected and normal cooling degree days for the utility's service territory are derived.	Type of Data Shown: _XX_Projected Test Year Ended 5/31/03 _XX_Prior Years Ended 5/31/01, 5/31/02 _XX_Historical Years Ended 1997 Through 3/31/01 Witness: R. L. McGee

PENSACOLA WEATHER STATION

COMMERCIAL COOLING DEGREE DAYS (62 DEG. F BASE)

	HISTORICAL 1997		HISTORICAL 1998		HISTORICAL 1999		HISTORICAL 2000			PRIOR YEAR Ended 5/31/01		PRIOR YEAR Ended 5/31/02		NORMAL TEST YEAR ENDED 5/31/03	
MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING	MONTH	CALENDAR	BILLING	CALENDAR	BILLING	CALENDAR	BILLING
JAN	46.5	64.0	2.5	10.0	46.5	37.0	36.0	29.0	JUN	550.5	534.0	550.0	500.0	550.0	507.0
FEB	47.5	35.0	9.5	4.0	38.0	58.0	41.5	31.0	JUL	717.5	655.0	640.0	591.0	640.0	591.0
MAR	195.5	127.0	52.0	21.0	36.0	29.0	94.5	61.0	AUG	662.0	650.0	616.0	623.0	616.0	623.0
APR	127.5	160.0	156.5	113.0	281.0	162.0	134.5	114.0	SEP	461.5	607.0	486.5	575.0	486.5	575.0
MAY	366.5	217.0	498.5	290.0	366.0	295.0	452.0	269.0	OCT	250.0	319.0	248.0	373.0	248.0	367.0
JUN	503.5	444.0	666.0	619.0	539.5	489.0	550.5	534.0	NOV	95.0	208.0	61.5	129.0	61.5	126.0
JUL	644.5	609.0	678.5	706.0	607.0	579.0	717.5	655.0	DEC	6.5	21.0	15.0	32.0	15.0	33.0
AUG	619.0	607.0	640.5	607.0	683.5	641.0	662.0	650.0	JAN	0.5	3.0	8.5	8.0	8.5	7.0
SEP	566.5	623.0	508.5	585.0	468.0	588.0	461.5	607.0	FEB	50.5	16.0	8.5	9.0	8.5	9.0
OCT	244.0	425.0	309.0	435.0	262.5	369.0	250.0	319.0	MAR	45.0	71.0	63.0	31.0	63.0	29.0
NOV	32.5	91.0	135.0	204.0	60.5	134.0	95.0	208.0	APR	215.5	139.0	215.5	133.0	215.5	127.0
DEC	13.5	28.0	82.0	129.0	12.5	44.0	6.5	21.0	MAY	397.5	303.0	397.5	310.0	397.5	304.0
ANNUAL	3,407.0	3,430.0	3,738.5	3,723.0	3,401.0	3,425.0	3,501.5	3,498.0	ANNUAL	3,452.0	3,526.0	3,310.0	3,314.0	3,310.0	3,298.0

Actual cooling degree days are based on hourly temperature observations recorded at the Pensacola, Florida weather station by the National Oceanic and Atmospheric Administration (NOAA). Daily Commercial cooling degree day values are calculated by subtracting the the 62 degree base from the daily mid-range temperature (maximum plus minimum divided by two). Calendar and billing month totals represent summations of daily values for calendar months and billing cycles, respectively. Normal values used in the forecast are based on 30-year climatological normals published by NOAA, which represents expected values based on observations from the data recorded during the period 1951-1980. Monthly weather data from the period 1980-1988 (for which hourly observations are readily available) are compared to the 30-year NOAA normals for the purpose of selecting months which compose the Typical Meterological Year.

Supporting Schedules: Recap Schedules:

Schedule F-14 TEMPERATURE AT TIME OF MONTHLY PEAKS

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: Provide the utility's service area's actual, projected (as applicable), and normal peak hour temperatures for each month of the test year and the five previous years. Provide the date, day of week and hour of peak. Provide a description of how actual, projected and normal peak hour temperatures for the utility's service area are derived.

Type of Data Shown:
_X__Projected Test Year Ended 5/31/03
_X__Prior Years Ended 5/31/01, 5/31/02
_X__Historical Years Ended 1996 Through 3/31/01
Witness: R. L. McGee

Date	Day of Week	Hour	Temperature	Actual (A) or Normal (N)
8-Jan-96	Monday	8	24	A
5-Feb-96	Monday	8	18	A
9-Mar-96	Saturday	9	31	A
22-Apr-96	Monday	17	77	A
23-May-96	Thursday	16	96	A
24-Jun-96	Monday	17	94	A
22-Jul-96	Monday	16	95	A
19-Aug-96	Monday	16	93	A
9-Sep-96	Monday	15	90	A
28-Oct-96	Monday	15	84	A
27-Nov-96	Wednesday	8	41	A
20-Dec-96	Friday	8	27	A
17-Jan-97	Friday	8	27	A
11-Feb-97	Tuesday	8	39	A
26-Mar-97	Wednesday	19	72	A
22-Apr-97	Tuesday	16	77	A
27-May-97	Tuesday	17	88	A
16-Jun-97	Monday	16	88	A
3-Jul-97	Thursday	17	99	A
18-Aug-97	Monday	16	88	A
3-Sep-97	Wednesday	17	97	A
1-Oct-97	Wednesday	17	87	A
17-Nov-97	Monday	7	36	A
16-Dec-97	Tuesday	7	32	A
26-Jan-98	Monday	8	42	A
9-Feb-98	Monday	8	44	A
13-Mar-98	Friday	7	37	A
15-Apr-98	Wednesday	16	75	A
28-May-98	Thursday	17	86	A
18-Jun-98	Thursday	16	95	A
6-Jul-98	Monday	17	93	A
27-Aug-98	Thursday	16	94	A
23-Sep-98	Wednesday	16	93	A
2-Oct-98	Friday	16	85	A
2-Nov-98	Monday	19	73	A
18-Dec-98	Friday	7	41	A

Date	Day of Week	Hour	Temperature	Actual (A) or Normal (N)
5-Jan-99	Tuesday	8	23	A
22-Feb-99	Monday	8	35	A
15-Mar-99	Monday	9	43	A
24-Apr-99	Saturday	17	82	A
25-May-99	Tuesday	17	83	A
4-Jun-99	Friday	15	90	A
29-Jul-99	Thursday	17	91	A
13-Aug-99	Friday	15	94	A
7-Sep-99	Tuesday	16	85	A
3-Oct-99	Sunday	16	84	A
4-Nov-99	Thursday	7	44	A
2-Dec-99	Thursday	7	43	A
26-Jan-00	Wednesday	8	29	A
1-Feb-00	Tuesday	8	40	A
30-Mar-00	Thursday	20	71	A
17-Apr-00	Monday	17	79	A
26-May-00	Friday	16	85	A
20-Jun-00	Tuesday	17	87	A
20-Jul-00	Thursday	14	96	A
17-Aug-00	Thursday	17	90	A
15-Sep-00	Friday	17	86	A
5-Oct-00	Thursday	17	80	A
22-Nov-00	Wednesday	7	30	A
20-Dec-00	Wednesday	7	20	A
4-Jan-01	Thursday	8	25	A
6-Feb-01	Tuesday	7	42	A
21-Mar-01	Wednesday	8	50	A
Apr-01	Week Day	16-17	87	N
May-01	Week Day	16-17	91	N

Date	Day of Week	Hour	Temperature	Actual (A) or Normal (N)
Jun-01	Week Day	16-17	95	N
Jul-01	Week Day	16-17	97	N
Aug-01	Week Day	16-17	94	N
Sep-01	Week Day	16-17	93	N
Oct-01	Week Day	16-17	92	N
Nov-01	Week Day	7-8	35	N
Dec-01	Week Day	7-8	36	N
Jan-02	Week Day	7-8	26	N
Feb-02	Week Day	7-8	29	N
Mar-02	Week Day	7-8	31	N
Apr-02	Week Day	16-17	87	N
May-02	Week Day	16-17	91	N
Jun-02	Week Day	16-17	95	N
Jul-02	Week Day	16-17	97	N
Aug-02	Week Day	16-17	94	N
Sep-02	Week Day	16-17	93	N
Oct-02	Week Day	16-17	92	N
Nov-02	Week Day	7-8	35	N
Dec-02	Week Day	7-8	36	N
Jan-03	Week Day	7-8	26	N
Feb-03	Week Day	7-8	29	N
Mar-03	Week Day	7-8	31	N
Apr-03	Week Day	16-17	87	N
May-03	Week Day	16-17	91	N

Actual peak hour temperatures are based on hourly temperature observations recorded at the Pensacola, Florida weather station by the National Oceanic and Atmospheric Administration (NOAA). Normal values used in the forecast are based on 30-year climatological normals published by NOAA, which represents expected values based on observations from the data recorded during the period 1951-1980. Monthly weather data from the period 1980-1988 (for which hourly observations are readily available) are compared to the 30-year NOAA normals for the purpose of selecting months which compose the Typical Meterological Year.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION Company: GULF POWER COMPANY Docket No. 010949-EI	EXPLANATION: Provide demonstration that the data submitted regarding the projected KWH and KW sales, operating revenues; billing determinants, conservation goals and programs; load forecast; fuel burn and, hence, the fuel inventory; projected expense; the earnings test and any requested attrition allowance is consistent.	Type of data shown: XX Projected Test Year Ended 05/31/2003 XX Prior Year Ended 05/31/2002 XX Historical Year Ended 12/31/2000 Witness: R. M. Saxon

Gulf's planning and budgeting process and the subsequent reviews By Gulf's Leadership Team, Budget Review Teams, or assigned representatives assure that the data and assumptions used in developing the various budgets and forecasts are consistent, accurate, and are reasonable at the time the projections are made.

The process begins with the long-range planning process where corporate direction is established through objectives, goals and strategies. This direction serves to provide consistency for the remaining part of Gulf's integrated planning, budgeting and monitoring system. The various groups such as Marketing Services, System Planning, Fuel Management, and Corporate Planning, develop the subsequent assumptions, submit these assumptions along with their budgets or forecasts to Gulf's Leadership Team for approval. The assumptions utilized in this forecast are provided in MFR's F-11 and F-17.

Supporting Schedules: Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Index to Assumptions

Supporting Schedules: F-9 F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63;D-10a; D-10b

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown: X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00 Witness: See Below

Forecast/Budget	Witness	Page
III. Construction Assumptions		
A. Construction Expenditures	Labrato Moore Howell Saxon Fisher	17
B. Electric Plant-in-Service	Labrato	18
IV. Balance Sheet Assumptions		
A. 13 Month Average Assets	Labrato Moore McMillan	19
B. 13 Month Average Capitalization and Liabilities	Labrato McMillan	23

Supporting Schedules: F-11

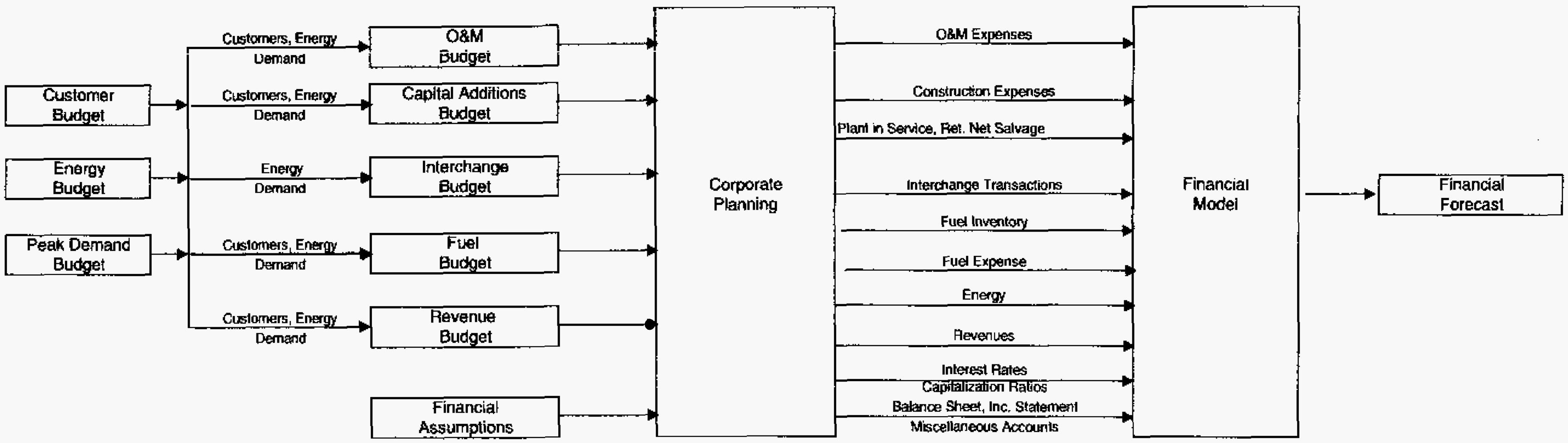
Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: R. M. Saxon

I. GENERAL ASSUMPTIONS

A. OVERVIEW

This MFR Schedule F-17 contains the assumptions used in developing the eight budgets comprising Gulf's financial forecast. MFR Schedule F-9 describes the models and methods used in developing the financial forecast.



FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: R. L. McGee

I. GENERAL ASSUMPTIONS

B. FORECAST OF CUSTOMER , ENERGY, PEAK DEMAND, AND REVENUE

Normal weather conditions are assumed. A Typical Meteorological Year (TMY) is used as the basis for development of energy sales and peak demand forecasts. The TMY consists of hourly weather data from "typical" months, in which mean monthly mid-range temperatures were observed to closely match thirty year means (normals) reported by the National Oceanic and Atmospheric Administration (NOAA) for the Pensacola, Florida weather station. Monthly minimum and maximum temperatures are also used as a criterion in selection of typical months.

Moderate growth in customers is expected to continue through 2003, but at lower rates than those experienced in recent years.

Energy sales and peak demand forecasts include the effects of Gulf's conservation and other market place initiatives. Gulf's projections incorporate electric price assumptions derived from the 2001 Gulf Power Official Long-Range Forecast and include estimated capital costs associated with the spring Lansing Smith Unit 3 capacity addition.

Base rate revenues were calculated using the FPSC approved rates in effect at the time of the forecast.

Economic projections were derived from Regional Financial Associates (RFA), a renowned economic services provider, now known as Economy.Com, Inc.

YEAR ENDED MAY, 2003 TEST YEAR GROWTH RATES	
CUSTOMERS	2.0%
TERRITORIAL KWH SALES	1.4%

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown: X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00 Witness: See Below

I. GENERAL ASSUMPTIONS

C. TEST YEAR OPERATION AND MAINTENANCE BUDGET WITHOUT FUEL AND PURCHASED POWER

Item		Amount	Witness	Assumption
1.	Inflation Factor - RFA		Saxon	Regional Financial Associates, currently known as Economy.Com, Inc.
	2001	2.60%		
	2002	2.43%		
	2003	2.40%		
2.	Construction Budget June Revision	(000's)	Saxon	Based on individual budget items called Plant Expenditure and developed using the process described in direct testimony. This information was used to estimate the O&M expenses of departments which have both maintenance and construction expenses.
	Major Generating Projects	$ 677		
	Production	$ 12,332		
	Transmission	$ 7,505		
	Distribution	$ 38,305		
	General Plant	$ 6,113		
	Total	$ 64,932		
3.	Estimate of Prime Interest Rate		Labrato	Provided by the SCS Financial Planning Department using RFA forecast.
	2nd Quarter 2002	8.500%		
	3rd Quarter 2002	8.920%		
	4th Quarter 2002	9.000%		
	1st Quarter 2003	9.000%		
	2nd Quarter 2003	9.000%		
4.	Retail Customers -			
	May-2003	389,181	McGee	Based on assumptions outlined in Section I.B. of this schedule and as described in direct testimony.
	Growth rate	2.0%		
5.	Retail Energy - MWH	10,282,958	McGee	Derived using assumptions outlined in Section I.B. of this schedule and as described in direct testimony.
	Growth rate	1.40%		

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FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

Item	Amount	Witness	Assumption
6. Peak Demand - MW	2,224 2.60%	McGee	Projected using assumptions outlined in Section I.B. of this schedule and described in direct testimony
7. Forecasted Composite		Saxon	Assumptions were based on inflation and current salary trends of other companies and utilities. Consideration was also given to estimated recruiting rates for certain entry level job families.
Wage and Salary			**Confidential information due to ongoing labor negotiations.
Increase Guidelines			
- Exempt	**		
- Non-exempt	**		
- Covered	**		
8. June 2002 - May 2003	(000's)		
Operations Expense:		Labrato	
Production	$ 35,563	Moore	Based on individual departmental budgets which incorporate the above assumptions and were developed using the process described in MFR F-11 and direct testimony of each witness.
Transmission	$ 5,771	Howell	
Distribution	$ 14,134	Fisher	
Customer Accounting	$ 16,605	Saxon	
Customer Service and Information	$ 13,907	Neyman	
Sales Expense	$ 1,363	Neyman	
Administrative and General	$ 41,592	McMillan	
Total Operations	$ 128,935		
9. June 2002 - May 2003			
Maintenance Expense:		Labrato	
Production	$ 49,822	Moore	Based on individual departmental budgets which incorporate the above assumptions and were developed using the process described in MFR F-11 and direct testimony of each witness.
Transmission	$ 2,318	Howell	
Distribution	$ 19,664	Fisher	
Administrative and General	$ 586	McMillan	
Total Maintenance	$ 72,390		

Schedule F-17 ASSUMPTIONS (000) Page 7 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: R. R. Labrato

I. GENERAL ASSUMPTIONS
D. TEST YEAR FINANCIAL ASSUMPTIONS

Item		Amount	Witness	Assumptions
1.	Interest Rates on Commercial Paper		Labrato	Interest rate assumptions are provided by SCS Financial Planning Department based upon RFA forecast.
	2nd Quarter, 2002	5.80%		
	3rd Quarter, 2002	6.20%		
	4th Quarter, 2002	6.30%		
	1st Quarter, 2003	6.30%		
	2nd Quarter, 2003	6.30%		
2.	Dividend Rates on Trust Preferred Securities	None	Labrato	Interest rate assumptions are provided by SCS Financial Planning Department based upon the forecast described above. Gulf's 'A' preferred stock dividend rate equals the 30-year T-bond rate plus 50 basis points.
3.	Dividends to Southern Company	$ 66,850	Labrato	Based on projections of Southern Company's cash dividends to its shareholders and its net operating expenses. Southern's total cash requirement is then apportioned to the operating companies such that dividends paid to Southern are proportionate to Southern's common equity investment in the operating company.
4.	Capital Contributions from Southern Company	$ 17,271	Labrato	Based on Southern Company's ability to market new issues of its common stock, the operating company's ability to earn an adequate return and to bring about significant improvements in the operating company's common equity ratio.
5.	Retirement of First Mortgage Bond	$ 0	Labrato	There are none scheduled in the test year.
6.	Retirement of Pollution Control Bond	$ 0	Labrato	There are none scheduled in the test year.
7.	Preferred Stock Issues	$ 0	Labrato	Based on Gulf's projected needs of cash to finance on-going operations. There are no Preferred Stock issues forecasted in the test year.
8.	Pollution Control Bond Issue, Total Authorized Amount	$ 0	Labrato	There are no Pollution Control Bond issues forecasted in the test year.

Schedule F-17 ASSUMPTIONS (000) Page 8 of 26

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

II. OPERATING ASSUMPTIONS

A. INCOME STATEMENT

Item		Amount	Witness	Assumptions
1.	Total Electric Revenue	$ 766,491	Neyman Labrato Moore Howell	Base rate revenues (billed and unbilled) are input to the Financial Model. The monthly fuel revenues (billed and unbilled) are based on forecasted monthly recoverable fuel expense, interchange costs and MWH sales. Conservation revenues (billed and unbilled) are calculated based on forecasted monthly recoverable expenses and MWH sales. Sales for Resale are interfaced from the Energy Budget described in MFR F-9. With the exception of Municipal Franchise Fees, Other Operating Revenues are input based on an analysis of the accounts. Municipal Franchise Fees are calculated using an input factor based on historical data. Capacity revenues (billed and unbilled) are calculated based on monthly net pool capacity. Environmental revenues (billed and unbilled) are calculated based on qualified monthly environmental expenditures.
2.	Fuel Expense (without Fuel Handling)	$ 308,818	Moore	The projected amount is derived from the Fuel Budget as described in MFR F-9. This expense is entered into the Financial Model by direct interface with the FOES model.
3.	Purchased Power	$ 17,653	Howell	The projected amount is derived from the Interchange Budget as described in MFR F-9. This expense is entered into the Financial Model by direct interface with the PROSYM model.
4.	Operations Expense (including Fuel Handling)	$ 128,935	Moore Howell Fisher McMillan Neyman Saxon	The projected amount is derived from the O&M Budget as described in section I.C. of this schedule. These expenses are summarized and input into the Financial Model.
5.	Maintenance Expense	$ 72,390	Moore Howell Fisher McMillan	The projected amount is derived from the O&M Budget as described in section I.C. of this schedule. These expenses are summarized and input into the Financial Model.
6.	Depreciation Expense	$ 77,720	Labrato	The projected amount is calculated by Financial Planning utilizing the Plant in Service inputs as described in section III.B. of this MFR. This amount is the electric depreciation only, it excludes depreciation associated with transportation, and merchandise activities.
7.	Amortization Expense	$ 4,517	Labrato	The projected amount is input into the Financial Model based on projected Plant balances as described in section III.B. of this MFR. It is electric only.
8.	Amortization Expense Investment Tax Credit	$ (1,831)	McMillan	The projected amount is the amortization of the Investment Tax Credits which are amortized over the life of related assets, per IRS regulations.

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

Schedule F-17 ASSUMPTIONS (000) Page 9 of 26

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown: X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00 Witness: See Below
COMPANY: GULF POWER COMPANY		
DOCKET NO. 010949-EI		

Item	Amount	Witness	Assumptions
9. Taxes Other than Income Taxes	$ 59,746	McMillan	All taxes other than income taxes are forecasted by applying actual, statutory, or average rates to applicable tax base. These taxes include Public Service Commission assessment fees, real and personal property taxes, gross receipts tax, franchise fees, state and federal unemployment tax, FICA, state motor vehicle licenses, federal highway use tax, and miscellaneous state and local taxes. The total amount is then reduced for taxes capitalized, taxes applicable to motor vehicles, and taxes applicable to merchandise activities.
10. Federal and State Income Taxes	$ 18,358	McMillan	Currently applicable federal and state income tax regulations are followed. The lowest possible tax payments are made currently. Assumptions include: - Federal tax rate = 35% - Full normalization of book and tax timing and basis differences - Most current IRS rules are followed - State tax rate = 5.5% - State of Florida tax regulations utilized
11. AFUDC - Debt and Equity	$ (706)	Labrato	AFUDC Rate: 7.35% The AFUDC rate is calculated based on a 13-month average jurisdictional capital structure and is input into a compounding formula to arrive at the monthly AFUDC rate. The monthly rate is applied to the projected average monthly eligible CWIP balance. Eligible CWIP equals projected monthly average CWIP less ineligible projects, and CWIP allowed in rate base.
12. Earnings on Temporary Cash	$ 0	Labrato	The projected amount is calculated by applying the applicable interest rate to the projected average monthly balance of temporary cash investments.
13. Other Income	$ (36)	Labrato	The projected amount includes the projected loss for merchandising, as well as the earnings on the funded portion of property insurance reserve. The loss occurs due to the closing of the company's merchandising business.
14. Other Income Deductions	$ 2,222	Saxon	The projected amount includes donations, civic membership, governmental expenses, and the amortization of Non-electric Investment Tax Credits.
15. Income Taxes on Other Income	$ (673)	McMillan	Currently applicable federal and state income tax regulations are followed. The lowest possible tax payments are made currently. See item 10 of this section for assumptions.

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; B-2; C-19; C-63; D-10a; D-10b

Schedule F-17 ASSUMPTIONS (000) Page 10 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Item	Amount	Witness	Assumptions
16. Interest on Long-Term Debt	$ 26,229	Labrato	The projected amount is calculated by applying each bond principal to the coupon interest rate and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
17. Interest on Pollution Control Debt	$ 8,736	Labrato	The projected amount is calculated by applying each bond principal to the coupon interest rate and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
18. Interest on Short-term Debt	$ 1,192	Labrato	The projected amount is calculated by applying the forecasted short-term interest rates, as described in section I.D. of this schedule, to the face amount of short-term debt projected to be outstanding.
19. Amortization of Debt Discount, Premium and Expense	$ 1,831	Labrato	The projected amount is calculated based on the embedded amortization amounts. No adjustments are made for new debt issues. The interest rate on new debt issues is projected to include the effect of debt-related costs over the life of the debt issued.
20. Trust Preferred Dividend Expense	$ 8,676	Labrato	The projected amount is calculated by multiplying each Trust Preferred principal by its interest rate and dividing by 12. The calculation is adjusted for any new issues or scheduled retirements.
21. Other Interest Expense	$ 921	Labrato	The projected amount is calculated based on applying the budgeted rate to the projected average monthly balance of Customer Deposits.
22. Preferred Dividends	$ 216	Labrato	The projected amount is calculated by multiplying each preferred principal by its interest rate and dividing by 12. The calculation is adjusted for any new issues and scheduled retirements.
23. Net Income After Dividends on Preferred Stock	$ 31,507		

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: R. G. Moore

II. OPERATING ASSUMPTIONS

B. AVERAGE ANNUAL NET UNIT HEAT RATES FOR PROJECTED TEST YEAR

Line No.	(A) Unit	(B) Average Net Heat Rates (BTU/KWH)
1	CRIST 1	14,940
2	CRIST 2	14,948
3	CRIST 3	13,966
4	CRIST 4	10,666
5	CRIST 5	10,385
6	CRIST 6	10,568
7	CRIST 7	10,196
8	SCHOLZ 1	12,862
9	SCHOLZ 2	12,677
10	SMITH 1	10,113
11	SMITH 2	10,045
12	SMITH 3	7,058
13	SMITH A	14,066
14	DANIEL 1	10,191
15	DANIEL 2	10,045
16	SCHERER 3	10,407

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; B-10b

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: R. G. Moore

II. OPERATING ASSUMPTIONS
C. OUTAGE RATES FOR PROJECTED TEST YEAR

Line No.	Unit	(A) Equivalent	(B) Weekend (1)	(C) Total (1)
1	CRIST 1	10.0%	2.70%	-0-
2	CRIST 2	10.0%	1.00%	-0-
3	CRIST 3	6.0%	0.80%	-0-
4	CRIST 4	5.0%	0.80%	-0-
5	CRIST 5	5.0%	1.80%	-0-
6	CRIST 6	5.5%	1.80%	-0-
7	CRIST 7	7.0%	2.70%	-0-
8	SCHOLZ 1	4.0%	2.20%	-0-
9	SCHOLZ 2	6.0%	2.00%	-0-
10	SMITH 1	5.4%	2.00%	-0-
11	SMITH 2	5.6%	3.50%	-0-
12	SMITH 3	4.9%	3.16%	-0-
13	SMITH A	7.0%	0.55%	-0-
14	DANIEL 1	5.3%	1.79%	-0-
15	DANIEL 2	5.3%	1.60%	-0-
16	SCHERER 3	2.3%	1.00%	-0-

(1) Not included as an assumption for the budget.

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: R. G. Moore

II. OPERATING ASSUMPTIONS
D. PLANNED MAINTENANCE FOR PROJECTED TEST YEAR

Line No.	Unit	(A) Start Date	(B) End Date	(C) Outage Duration (Days)	(D) Total Days
1	CRIST 1	No outages planned			
2	CRIST 2	No outages planned			
3	CRIST 3	No outages planned			
4	CRIST 4	10/05/02	10/27/02	23	23
5	CRIST 5	11/09/02	12/01/02	23	23
6	CRIST 6	02/08/03	03/02/03	23	23
7	CRIST 7	03/22/03	04/13/03	23	23
8	SCHOLZ 1	12/07/02	12/15/02	8	8
		02/01/03	02/23/03	23	23
9	SCHOLZ 2	10/12/02	10/20/02	9	9
		03/15/03	03/23/03	8	8
10	SMITH 1	10/26/02	11/03/02	9	9
		01/04/03	01/26/03	23	23
11	SMITH 2	11/09/02	11/17/02	9	9
		03/29/03	04/13/03	16	16
12	SMITH 3	10/02/02	10/06/02	5	5
		05/03/03	05/16/03	14	14
13	SMITH A	-	-	-	-
14	DANIEL 1	01/11/03	03/23/03	73	73
15	DANIEL 2	-	-	-	-
16	SCHERER 3	04/19/03	05/18/03	29	29

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: R. G. Moore

II. OPERATING ASSUMPTIONS

E. NET UNIT CAPACITY RATINGS FOR PROJECTED TEST YEAR

		Net (Summer and Winter)
Crist	1	24.0
Crist	2	24.0
Crist	3	35.0
Crist	4	78.0
Crist	5	80.0
Crist	6	302.0
Crist	7	477.0
Scholz	1	46.0
Scholz	2	46.0
Smith	1	162.0
Smith	2	189.0
Smith	3	574.0
Smith	A	32.0
Daniel	1	253.5
Daniel	2	255.0
Scherer	3	210.0

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Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b;C-2; C-19; C-63; D-10a; D-10b

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

II. OPERATING ASSUMPTIONS

F. OTHER FUEL BUDGET ASSUMPTIONS FOR TEST YEAR

Item		Witness	Assumption
1.	Time Period Covered June 2002 - May 2003		
2.	System Generation Expansion Plan	Moore	a. Generation Expansion Plan as provided by System Planning. b. Preliminary and commercial operation dates as provided by SCS. c. Unit retirement dates as provided by the operating companies.
3.	Load and KWH Energy Estimates	McGee Howell	a. Official estimates provided by the operating companies. b. Sales to nonassociated companies as estimated by SCS. (1) Unit Power - included in official budget
4.	Maintenance Schedules	Moore	Official maintenance schedules as provided to SCS by the operating companies as stated in section II.D. of this schedule.
5.	Preliminary Generation for New Units	Howell	Monthly KWH preliminary energy requirements as provided by operating companies.
6.	Heat Rates	Moore	Heat rates provided by SCS.
7.	Coal	Moore	a. Beginning Inventory Values as provided by the operating companies. b. Desired plant inventory values as provided by the operating companies. c. Coal quality as provided by the operating companies. d. Beginning prices (See MFR B-17a) (1) F.O.B. mine or loaded cost as recommended by SCS Fuel Services and approved by the operating company involved. The actual billing cost and recommended accruals per SCS Contract Administration records for non cost-based contracts and committed spot. These values were adjusted for typical Btu variance from contract values and appropriate state use taxes were added, if applicable. (2) Coal transportation cost on contract and spot as recommended by SCS Fuel Services and approved by the operating company involved. e. Price escalation rates. (1) The escalation rates for contract, uncommitted spot, unknown contract coal, and coal transportation and the timing thereof are reflected as agreed to by the System Fuels Committee. These rates include background inflation forecast as well as market forecast.

Schedule F-17 ASSUMPTIONS (000) Page 16 of 26

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
DOCKET NO. 010949-EI		Historical Year 12/31/00
		Witness: See Below

Item	Witness	Assumption
8. Oil	Moore	a. Beginning inventory values as provided by the operating companies. b. Desired plant capacity inventory levels. (1) Crist 90% (2) Smith A 90% (3) Smith 80% (4) Scholz 100% (5) Daniel 67% (6) Scherer 95% c. Boiler lighter oil burn: Quantity projected to be bumed as recommended by SCS and approved by the operating company involved. d. Oil quality--Btu/gallon and % sulfur content as recommended by SCS and approved by the operating company involved. e. Beginning prices. (See MFR B-17a): Delivered prices in cents/MMBtu as recommended by SCS and approved by the company involved. f. Price escalation rates - The escalation rates for oil and the timing thereof are as agreed to by the System Fuels Committee. These rates include background inflation forecast as well as market forecast.
9. Natural Gas	Moore	a. Natural gas availability - It is assumed that all natural gas required can be obtained for the budget/forecast period. b. Boiler lighter gas burn - Quality projected to be burned as recommended by SCS and approved by the operating company. c. Boiler gas burn - For all dual fired boiler units, only natural gas is to be shown bumed in the budget/forecast. d. Natural gas quality - Btu/mcf as recommended by SCS and approved by the operating company involved. e. Beginning prices: Delivered prices as recommended by SCS and approved by the operating company involved. f. Price escalation rates - The escalation rates for gas and the timing thereof are as agreed to by the System Fuels Committee. These rates include background inflation forecast as well as market forecast.

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Supporting Schedules: F-9, F-11

Recap Schedules:B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-10; C-63; D-10a; D-10b

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

III. CONSTRUCTION BUDGET

A. TEST YEAR CONSTRUCTION EXPENDITURES

Item		Amount	Witness	Assumption
Facilities Requirements				
1.	Major Generation	$ 677	Moore	Consists of expenditures at Plant Smith Unit 3 for final completion.
2.	Production Plant Projected	$ 12,332	Moore	Proposed additions and retirements of production plant are based on such factors as service life, failure rates, performance, operating experience, environmental regulations, technological improvements, obsolescence, additional requirements, etc.
3.	Transmission	$ 7,505	Howell	Transmission expansion plans reflect the need to serve new customers, to strengthen the transmission system to meet additional demand, and to replace damaged, worn-out, or obsolete facilities. New business projects include major new customers, or major additional loads at existing customer locations.
4.	Distribution	$ 38,305	Fisher	Distribution expansion plans reflect the need to serve our growing customer requirements. New business projects include the purchase and installations of watthour and watthour demand meters, overhead and underground transformers and high pressure sodium lighting facilities are a result of customer growth. Also included is the construction of additions, extensions, and improvements for the connection of new residential, commercial, and industrial customers. Miscellaneous additions and improvements include the cutouts, arresters, and reclosers.
5.	General Plant	$ 6,113	Fisher Saxon	Projected on the need to replace general plant items such as vehicles, test equipment, tools, office equipment, and communication equipment that are no longer serviceable, and to insure an adequate number of such items are available so that the appropriate personnel can fulfill their job requirements in an effective and efficient manner.
6.	Total Construction Expenditures	$ 64,932		

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

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FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

III. CONSTRUCTION BUDGET
B. TEST YEAR ELECTRIC PLANT IN SERVICE

Item	Amount	Witness	Assumption
1. Gross Additions to Plant:		Labrato	The amounts are based on the May 14, 2001 Construction Budget as approved by Gulf's management. Plant-In-Service amounts, in-service year, and plant classification were provided by the responsible departments.
Production	$ 19,124		
Transmission	$ 29,015		
Distribution	$ 42,560		
General Plant	$ 5,002		
Total Gross Additions to Plant	$ 95,701		
2. Retirements	$ 18,125	Labrato	The amount was based on the May 14, 2001 Construction Budget as approved by Gulf's management. Amounts, dates and function were provided by the responsible departments.
3. Net Salvage	$ 2,178	Labrato	The amount was based on the May 14, 2001 Construction Budget as approved by Gulf's management. Amounts, dates and function were provided by the responsible departments.
4. Depreciation and Amortization Rates	Various	Labrato	The rates and amounts were based on the FPSC approved depreciation study and investment by FERC account as of March 31, 2001.
5. Provision for Depreciation and Amortization Expenses	$ 82,680	Labrato	The amount was projected by applying the FPSC approved rates and amortization amounts to the average monthly balance of depreciable plant by function. This amount is calculated by the Financial Model.

Supporting Schedules: F-9, F-11 Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

Schedule F-17 ASSUMPTIONS (000) Page 19 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

IV. BALANCE SHEET ASSUMPTIONS

13-MONTH AVERAGE ASSETS

Item	Amount	Witness	Assumption
Utility Plant			
1. Electric Plant in Service	$2,277,763	Labrato	The projected balances were derived by adding to the balance at March 31, 2001 the projected additions and deducting the projected retirements as described in section III.B. of this schedule.
2. Electric Plant for Future Use	$ 3,164	Labrato	The projected balances were derived by adding to the balance at March 31, 2001 the projected additions as described in section III.B. of this schedule.
3. Construction Work in Progress	$ 28,264	Labrato	The projected balances were calculated by adding to the balance at March 31, 2001, the 2002 budgeted construction expenditures through May 2003 and deducting the projected closings to Plant-In-Service and Plant Held for Future Use, as described in section III.B. of this schedule.
4. Plant Acquisition Adjustment	$ 4,861	Labrato	The projected balances were calculated by reducing each month's balance by the amount of amortization related to the Plant Acquisition Adjustment. Amortization is $21,276 per month.
5. Accumulated Provision for Depreciation and Amortization	$ (972,552)	Labrato	The projected balances were calculated by adding to the balance at March 31, 2001 the projected provision for depreciation and net salvage values and deducting the projected retirements budgeted. The provision for depreciation was calculated using the methodology described in section III.B. of this schedule. Retirements and Net Salvage were based on the 2002 Construction Budget.
6. Net Utility Plant	$1,341,500		
7. Other Special Funds	$ 8,264	Labrato	The projected balance is the funded portion of the property insurance reserve. The funding of the reserve occurs each January and is calculated by applying the effective after tax rate of 61.43% to the projected year-end balance of the property insurance reserve account each December.
8. Non-Utility Property	$ 454	Labrato	The projected balance was based on the actual balance at March 31, 2001 with adjustments made for additions through May 2003.

Schedule F-17 ASSUMPTIONS (000) Page 20 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions use In developing projected or estimated data. At a minimum, state assumptions use for balance sheet, income statement and sales forecas

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Item		Amount	Witness	Assumption
9.	Other Property and Investments-Other	$ 808	Labrato	The projected balance was based on the actual balance at March 31, 2001 adjusted for projections for Deferred Compensation Trust.
10.	Total Other Property and Investments	$ 9,526		
Current Assets				
11.	Cash	$ 3,980	Labrato	The projected balance is maintained as a static balance by the Financial Model as an estimate which approximates operating cash requirements.
12.	Special Deposits	$ 5	Labrato	The projected balance was based on the actual balance at March 31, 2001. No changes were projected for the test year.
13.	Working Funds	$ 272	Labrato	The projected balance was derived based on a 24 month historical average. Projected unusual items are added to the balance.
14.	Temporary Cash Investments	$ 0	Labrato	The projected balance is calculated by the Financial Model based on the projected sources and uses of funds. No balances are projected for the test year.
15.	Customer Accounts Receivable	$ 33,671	Labrato	The projected balance was calculated by the Financial Model by taking Territorial Revenues (net of Unbilled) plus Other Operating Revenues and dividing by the number of days in the month to get Average Daily Revenues. This figure is then multiplied by a Monthly Average Days Factor (based on historical data) to arrive at Customer Accounts Receivable.
16.	Accrued Unbilled Revenue	$ 26,494	Labrato	The projected balance was derived based on the March 31, 2001 actual balance adjusted for monthly net increase or decrease in unbilled revenue.
17.	Other Accounts and Notes Receivable	$ 15,667	Labrato	The projected balance was derived based on March 31, 2001 actual balance increased by projected changes. This account includes receivables from merchandise activities, employee loans, property damage, and miscellaneous accounts receivable.

Schedule F-17 ASSUMPTIONS (000) Page 21 of 26

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

Item		Amount	Witness	Assumption
18.	Accumulated Provisions fo Uncollectible Accounts	$ (1,012)	Labrato	The projected balance was calculated by applying a historical two-year average ratio for uncollectibles to the monthly customer accounts receivable balance plus a projected provision for uncollectible merchandise accounts receivable.
19.	Receivables from Associated Companies	$ 8,670	Labrato	The projected balance includes the Interchange transactions when Gulf is a net seller to the Southern Company pool, and an estimate of other miscellaneous receivables from associated companies.
20.	Interest and Dividends Receivable	$ 184	Labrato	The projected balance was calculated by applying a ratio based on a historical two year average balance to monthly earnings on temporary cash investments and adding interest earned by the Funded Property Insurance Reserve. The balance is projected interest and dividends receivable.
21.	Fuel Stock	$ 31,922	Moore	The projected balance is a function of the Fuel Budget as described in MFR F-11.
22.	In-Transit Coal	$ 13,130	Moore	The projected balance was derived by taking a historical ratio of in-transit coal to generation for each plant. This percentage is then multiplied by the projected monthly generation for each plant. The average of these in-transit coal tons is calculated for each projected year and then multiplied by the weighted yearly average F.O.B. mine price of coal for each plant.
23.	Plant Materials and Supplies	$ 29,620	Labrato	The projected balance was derived based on historical and projected balances developed by the General Services Department and the Power Supply Department.
24.	Prepayments	$ 39,497	Labrato	The projected balance was based on estimated insurance premiums and related amortization, railcar lease, pensions, long term service agreement, and other miscellaneous prepayments.
25.	Accrued Vacations	$ 4,712	Labrato	The projected balance was based on an analysis by the payroll department taking into account number of employees, years of service and hourly rates.
26.	Total Current Assets	$ 206,812		
Deferred Debits				
27.	Unamortized Debt Expense	$ 2,098	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 reduced by monthly net amortization based on the embedded expenses.

Supporting Schedules: F9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

Schedule F-17 ASSUMPTIONS (000) Page 22 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Item		Amount	Witness	Assumption
28.	Accumulated Deferred Income Taxes	$ 54,276	McMillan	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for the projected provisions and pay backs related to the property insurance, injuries and damages, warranty reserves, early retirement, and medical payments reserve.
29.	Regulatory Tax Asset	$ 18,736	McMillan	This amount is based on the actual balance at March 31, 2001, adjusted for estimated changes. This account appears on the balance sheet in compliance with FAS 109.
30.	Unamortized Loss on Reacquired Debt	$ 13,161	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 reduced by monthly amortization.
31.	Other Deferred Debits	$ 11,861	Labrato	The projected balance was based on the actual balance at March 31, 2001 adjusted for the projected changes. This account includes preliminary survey investigation charges, unallocated clearing accounts, and miscellaneous other deferred debit items.
32.	Total Deferred Debits	$ 100,132		
33.	Total Assets	$ 1,657,970		

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

Schedule F-17 | ASSUMPTIONS (000) | Page 23 of 26

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO. 010949-EI	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown: X Projected Test Year Ended 5/31/03 Prior Year Ended 5/31/02 Historical Year 12/31/00 Witness: See Below

Item	Amount	Witness	Assumption
Capitalization			
1. Common Stock	$ 38,060	Labrato	The projected balance was based on the March 31, 2001 actual balance. No changes were projected for the test year.
2. Other Paid-In Capital	$ 381,627	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for the projected capital contribution from Southern Company as described in section I.D. of this schedule.
3. Premium on Preferred Stock	$ 12	Labrato	The projected balance was based on the March 31, 2001 actual balance. No changes were projected for the test year.
4. Retained Earnings	$ 127,489	Labrato	The projected balance was derived based on the March 31, 2001 actual balance increase by the projected net income before preferred less common and preferred stock dividends declared.
5. Preferred Stock	$ 119,236	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for any projected retirements or issues of preferred stock as outlined in section I.D. of this schedule. There are no new issues of Preferred Stock projected for the test year. This balance includes Trust Preferred Stock.
6. First Mortgage Bonds	$ 85,000	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for the retirements of outstanding issues as described in section I.D. of this schedule. There are no new First Mortgage Bond issues projected for the test year.
7. Pollution Control Liability	$ 169,630	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for scheduled retirements as described in section I.D. of this schedule There are no new Pollution Control Liability Issues projected for the test year.
8. Other Long Term Debt	$ 280,002	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 adjusted for projected issues or retirements. There are none scheduled for the test year.

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

Schedule F-17 | ASSUMPTIONS (000) | Page 24 of 26

FLORIDA PUBLIC SERVICE COMMISSION	EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.	Type of Data Shown:
COMPANY: GULF POWER COMPANY		X Projected Test Year Ended 5/31/03
		Prior Year Ended 5/31/02
		Historical Year 12/31/00
DOCKET NO. 010949-EI		Witness: See Below

Item		Amount	Witness	Assumption
9.	Unamortized Debt Discount and Premium	$ (6,055)	Labrato	The projected balance was derived based on March 31, 2001 actual balance reduced by the monthly net amortization of discounts and premiums.
10.	Total Capitalization	$1,195,001		
Current Liabilities				
11.	Notes Payable	$ 19,233	Labrato	The projected balance was calculated by the Financial Model based on the projected sources and uses of funds.
12.	Construction Related Accounts Payable	$ 1,538	Labrato	The projected balance was derived by applying a historical two year average ratio to monthly construction expenditures (less Plant Scherer expenditures). This account includes accounts payable - construction and contract retentions.
13.	Other Accounts Payable	$ 31,462	Labrato	The projected balance was derived using historical accounts payable ratios to fuel and other operation and maintenance expense applied to projected expenses for those accounts. Also included in this account is the monthly unaudited accounts payable invoices dealing with plant accounts.
14.	Payables to Associated Companies	$ 7,253	Labrato	The projected balance was derived by applying historical accounts payable ratios to fuel and other operation and maintenance expenses associated with co-owned plants plus monthly interchange transactions when Gulf is a net purchaser from the Southern Company pool.
15.	Customer Deposits	$ 13,969	Labrato	The projected balance was derived based on linear regression calculations, taking into account projected residential and commercial customer growth rates.

Schedule F-17 ASSUMPTIONS (000) Page 25 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Item	Amount	Witness	Assumption
16. Income Taxes Accrued	$ 5,020	McMillan	The projected balance was derived based on the March 31, 2001 actual balance plus projected monthly accruals from the income statement reduced by the estimated tax payments.
17. Other Taxes Accrued	$ 10,806	McMillan	The projected balance was derived based on the March 31, 2001 actual balance plus projected monthly accruals reduced by projected payments based on the applicable payment dates. This account included Public Service Commission assessment fees, real and personal property taxes, gross receipts taxes, franchise fees, FICA, federal and state unemployment taxes, and miscellaneous state and local taxes.
18. Interest Accrued	$ 10,612	Labrato	The projected balance was calculated based on the interest rate and payment dates of embedded debt issues as of March 31, 2001 plus any issues or retirements. This account also includes amounts related to the interest on customer deposits.
19. Miscellaneous Accounts Payable	$ 10,229	Labrato	The projected balance was calculated based on the interest rates and payment dates of embedded debt issues at March 31, 2001 adjusted for scheduled retirements of preferred stock as outlined in section I.D. There are no new issues of preferred stock projected in the test year. Projections include projected quarterly dividends payable to Southern Company.
20. Tax Collections Payable	$ 1,278	McMillan	The projected balance was based on the historical relationship of taxes to their applicable base and on a nine month historical average for payroll taxes.
21. Accrued Vacations	$ 4,712	Labrato	The projected balance was based on an analysis by the payroll department taking into account the number of employees, years of service and hourly rates.
22. Other Current Liabilities	$ 1,459	Labrato	The projected balance was based on a 12-month historical average and adjusted for projected changes.
23. Total Current Liabilities	$ 117,571		

Supporting Schedules: F-9, F-11

Recap Schedules: B-2a; B-2b; B-3; B-8a; B-8b; C-2; C-19; C-63; D-10a; D-10b

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Schedule F-17 ASSUMPTIONS (000) Page 26 of 26

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO. 010949-EI

EXPLANATION: For a projected test year, provide a schedule of assumptions used in developing projected or estimated data. At a minimum, state assumptions used for balance sheet, income statement and sales forecast.

Type of Data Shown:
X Projected Test Year Ended 5/31/03
Prior Year Ended 5/31/02
Historical Year 12/31/00
Witness: See Below

Item		Amount	Witness	Assumption
Deferred Credits				
24.	Unamortized Investment Tax Credits	$ 22,113	McMillan	The projected balance was derived using the actual balance at March 31, 2001 reduced by the amortization of ITC based on the useful life of the asset giving rise to the tax credit.
25.	Other Deferred Credits	$ 34,131	Labrato	The projected balance was derived based on the actual balance at March 31, 2001 and the estimated monthly changes. This account includes customer advance payments for electric service, deferred revenue on pole attachment rentals, appliance sales deferred interest revenue, and miscellaneou other deferred credit items.
26.	Total Deferred Credits	$ 56,244		
27.	Operating Reserves	$ 51,469	Labrato	The projected balance was based on an estimate of the amounts needed to cover future contingencies.
28.	Other Deferred Income Taxes	$ 206,366	McMillan	The projected balance was derived based on March 31, 2001 actual balance adjusted for the projected provisions and paybacks relating to accrued vacations, unbilled revenue, pensions and loss on reacquired debt, and the property related depreciation timing differences.
29.	Regulatory Tax Liability	$ 31,319	McMillan	This amount is based on the actual balance at March 31, 2001, adjusted for estimated changes. This account appears on the balance sheet in compliance with FAS 109.
30.	Total Other Deferred	$ 237,685		
31.	Total Capitalization and Liabilities	$ 1,657,970		

Supporting Schedules: F-11F-9

Recap Schedules: B-2a;B-2b; B-3;B-8a; B-8b;C-2;C-19;C-63; D-10a; D-10b

NUCLEAR PLANTS - DECOMMISSIONING

FLORIDA PUBLIC SERVICE COMMISSION COMPANY: GULF POWER COMPANY DOCKET NO.: 010949-EI	EXPLANATION Provide data as specified regarding the decommissioning of nuclear plants.	Type of Data Shown: XX Projected Test Year Ended 05/31/2003 XX Prior Year Ended 05/31/2002 XX Historical Test Year Ended 12/31/2000 Witness: R.G. Moore

This MFR is not applicable, Gulf Power has no nuclear plants.

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Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide data as specified regarding spent nuclear fuel and radioactive waste storage.

Type of Data Shown:
___ Projected Test Year Ended 05/31/2003
___ Prior Year Ended 05/31/2002
___ Historical Test Year Ended 12/31/2000
Witness: R.G. Moore

Not applicable. Gulf Power has no nuclear plants.

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Supporting Schedules: Recap Schedules:

Schedule F-20

NUCLEAR PLANTS - STORAGE FACILTIES

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: GULF POWER COMPANY

DOCKET NO.: 010949-EI

EXPLANATION: Provide data as specified for each plant site or facility at which spent fuel or radioactive waste is stored.

Type of Data Shown:
___ Prior Year Ended 05/31/03
___ Projected Test Year Ended 05/31/02
___ Historical Test Year Ended 12/31/00
Witness: R.G. Moore

Line No.	Facility Name	Spent Fuel or Waste?	Volume of Fuel or Waste Stored	Annual Volume of Spent Fuel or Waste Generated	Remaining Capacity	Number of Fuel Assemblies	Facility Annual Operating Cost	Facility Capital Cost	Description of Facility

Not applicable. Gulf has no nuclear plants.

Supporting Schedules:

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Gulf Power Company

DOCKET NO. 010949-EI

EXPLANATION: Supply a proposed public notice of the company's request for a rate increase suitable for publication.

Type of Data Shown:
XX Projected Test Year Ended 05 /31/03
Prior Year Ended 05/31/02
Historical Year Ended 12/31/00
Witness: R. R. Labrato

NOTICE TO CUSTOMERS

On September 10, 2001, Gulf Power Company filed with the Florida Public Service Commission a request for approval to increase the Company's annual retail revenues by $69,867,000. The increase to total retail revenue will be 11.91 percent. This request has been assigned Docket No. 010949-EI.

The primary reason that Gulf Power Company is requesting this rate increase is the addition of a new 574 (mW) combined cycle, generating unit presently under construction at Lansing Smith Plant near Panama City, Florida that will cost over $220 million when completed in May of 2002. The unit, Smith 3, is expected to be in-service by June 1, 2002.

In addition to expenses related to Smith Unit 3, several factors will have contributed to the increase in the Company's cost of providing electric service during the 12-year period since 1990, the Company's last base rate increase, to the end of 2002. During this period , Gulf will have added over 100,000 customers, a 32 percent increase, and will have experienced inflation of approximately 39 percent. The Company will have also constructed new infrastructure of approximately 1400 miles of distribution and 90 miles of transmission lines.

The present rates will remain in effect until new rates become operative under Florida Law. Copies of the rate case filing, including rate schedules, are available for inspection at any Gulf Power Company office. Company personnel are available at all Gulf Power offices to answer questions concerning this request. They may be contacted at the address or telephone number shown on your electric service bill.

For your information, we are providing the address and telephone number of the Florida Public Service Commission's Consumer Affairs Department.

Consumer Affairs Department
Florida Public Service Commission
Beverlee DeMello, Director
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
1-800-342-3552

Supporting Schedules: Recap Schedules: