J. Randy DeRieux
Assistant Treasurer and
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April 25, 2002

ALABAMA POWER
A SOUTHERN COMPANY

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555-0001

Joseph M. Farley Nuclear Plant
Annual Submission Reports

Re: Docket Nos.: 50-348
50-364

Ladies & Gentlemen:

Enclosed is the annual submission of Alabama Power Company with respect to the retrospective premium guarantee required under the Price Anderson Act, as amended, applicable to its Joseph M. Farley Nuclear Plant. We have elected to satisfy this guarantee requirement by submitting annual certified financial statements and cash projections, showing that a cash flow can be generated and would be available for payment of retrospective premiums up to $20,000,000 within three months after submission of the statement. In this connection, enclosed are the following:

1. 2001 Annual Report which includes financial statements for the calendar year 2001, together with the report on such statements by Arthur Andersen & Co., independent public accountants;
2. Unaudited Financial Statements for the quarter ended March 31, 2002;
3. Cash Flow Projections for the period January 1, 2002 through December 31, 2002, showing that cash flow of $20,000,000 can be generated and would be available for payment of retrospective premiums within three months after submission of the statement.

Please acknowledge receipt of the enclosures by signing and returning the enclosed copy of this letter.

Very truly yours,

J. Randy DeRieux

JRD:lw
Enclosures

cc: w/attachments
Southern Nuclear Operating Company
Mr. L. M. Stinson, General Manager – Plant Farley

U. S. Nuclear Regulatory Commission, Washington, D.C.
Mr. F. Rinald, Licensing Project Manager – Farley

U. S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. T. P. Johnson, Senior Resident Inspector – Farley

M004

ALABAMA POWER COMPANY

STATEMENT OF INCOME
(THOUSANDS OF DOLLARS)

	3 Months Ended 3/31/02
OPERATING REVENUES:	
Revenues	$ 802,249
OPERATING EXPENSES:	
Operation --	
Fuel	208,634
Purchased & interchange power, net	48,501
Other	121,724
Maintenance	76,814
Depreciation & amortization	98,275
Taxes other than income taxes	57,500
Federal and State income taxes	50,994
Total Operating Expenses	662,442
OPERATING INCOME	139,807
OTHER INCOME (EXPENSES):	
Allowance for equity funds used during construction	3,007
Income from subsidiary	861
Other, net	(5,811)
INCOME BEFORE INTEREST CHARGES	137,864
INTEREST CHARGES:	
Interest on long-term debt	59,487
Allowance for debt funds used during construction	(1,940)
Amortization of debt discount, premium and expenses, net	3,134
Other interest charges	987
Net Interest Charges	61,668
NET INCOME	76,196
DIVIDENDS ON PREFERRED STOCK	3,656
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$ 72,540

This statement reflects the usual accounting practices of the Company on the basis of interim figures and is subject to audit and end of year adjustments.

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ALABAMA POWER COMPANY

Internal Cash Flow for
Joseph M. Farley Nuclear Power Station

(Thousands of Dollars)

	2001 Actual	2002 Projections
Net Income	$ 402,253	$ 456,787
Less Dividends Paid	408,842	446,041
Retained Earnings	(6,589)	10,746
Adjustments:		
Depreciation and Amortization	437,490	473,820
Deferred Income Taxes and Investment Tax Credits	(21,569)	(3,730)
Allowance for Equity Used During Construction	7,092	11,913
Total Adjustments	423,013	482,003
Internal Cash Flow	$ 416,424	$ 492,749
Average Quarterly Cash Flow	$ 104,106	$ 123,187
Percentage Ownership in all Operating Nuclear Units:		
Joseph M. Farley Units 1 and 2		100%
Maximum Total Contingent Liability		$ 20,000

This statement reflects the usual accounting practices of the Company on the basis of interim figures and is subject to audit and end of year adjustments.

ALABAMA POWER COMPANY
BALANCE SHEET
CONSOLIDATED WITH ALABAMA POWER CAPITAL TRUSTS I, II & III
(Stated in Thousands of Dollars)

ASSETS	At March 31, 2002	At March 31, 2001
UTILITY PLANT:		
Plant in service, at original cost	$ 13,227,382	$ 12,557,522
Less - Accumulated provision for depreciation and amortization	5,393,858	5,184,726
	7,833,524	7,372,796
Nuclear fuel, at amortized cost	77,108	87,923
Construction work in progress	457,469	796,709
	8,368,101	8,257,428
OTHER PROPERTY AND INVESTMENTS:		
Equity investments in subsidiaries	45,685	39,924
Nuclear decommissioning trusts	311,639	304,840
Miscellaneous	16,987	14,037
	374,311	358,801
CURRENT ASSETS:		
Cash	32,193	10,731
Special Deposits	0	0
Temporary cash investments	0	0
Investment securities	0	0
Receivables -		
Customer accounts receivable	316,267	485,161
Other accounts and notes receivable	61,464	40,458
Affiliated companies	60,593	43,798
Accumulated provision for uncollectible accounts	(5,715)	(5,974)
Refundable income taxes	0	0
Fossil fuel stock, at average cost	94,927	92,397
Materials and supplies, at average cost	168,820	157,723
Allowance Inventory	21,101	15,973
Prepayments -		
Income taxes	0	0
Other	84,614	65,503
Other current assets - SFAS 133	21,224	0
Vacation pay deferred	32,324	31,711
	887,812	937,481
Debt expense, being amortized	8,109	8,409
Debt redemption expense, being amortized	75,179	74,029
Nuclear decontamination and decommissioning fund	21,015	24,588
Prepaid pension cost	344,044	282,302
Regulatory assets	309,178	344,826
Miscellaneous	109,088	104,345
	866,613	838,499
TOTAL ASSETS	$ 10,496,837	$ 10,392,209

4/17/02 +

This statement reflects the usual accounting practices of the Company on the basis of interim figures and is subject to audit and end of year adjustments.

ALABAMA POWER COMPANY
BALANCE SHEET
CONSOLIDATED WITH ALABAMA POWER CAPITAL TRUSTS I, II & III
(Stated in Thousands of Dollars)

CAPITALIZATION AND LIABILITIES	At March 31, 2002	At March 31, 2001
CAPITALIZATION:		
Common stock equity	$ 3,277,133	$ 3,164,833
Preferred stock	317,512	317,512
Company obligated mandatorily redeemable preferred securities *	347,000	347,000
Long-term debt	3,742,657	3,425,059
	7,684,302	7,254,404
CURRENT LIABILITIES:		
Preferred stock due or to be redeemed within one year	0	0
Long-term debt due or to be redeemed within one year	904	846
Notes payable to banks	0	56,000
Commercial paper	96,833	390,339
Accounts payable -		
Affiliated companies	94,260	105,944
Other	91,668	93,295
Customer deposits	43,419	38,217
Taxes accrued -		
Federal and state income	158,090	111,108
Other	38,293	37,329
Interest accrued	61,162	46,109
Distributions accrued	5,816	79
Vacation pay accrued	32,324	31,711
Miscellaneous	53,492	51,099
	676,261	962,076
DEFERRED CREDITS AND OTHER LIABILITIES:		
Accumulated deferred income taxes	1,369,097	1,398,836
Accumulated deferred investment tax credits	235,491	246,516
Prepaid capacity revenues, net	39,099	52,634
Regulatory liabilities	198,571	217,894
Nuclear decontamination and decommissioning fund	16,812	20,490
Natural disaster reserve	12,981	18,790
Miscellaneous	264,223	220,569
	2,136,274	2,175,729
TOTAL CAPITALIZATION AND LIABILITIES	$ 10,496,837	$ 10,392,209

* Substantially all assets of Alabama Power Capital Trust I, II & III are junior subordinate notes issued by the company. Upon redemption of such notes, the Trust securities will be mandatorily redeemable. See Note 9 to the financial statements of Alabama Power Company in Item 8 of the 1998 Form 10-K for further details.

Corporate Accounting Department

ALABAMA POWER

A SOUTHERN COMPANY

2001 ANNUAL REPORT

www.alabamapower.com

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SUMMARY

	2001	2000	Percent Change
Financial Highlights *(in millions)*:			
Operating revenues	**$3,587**	$3,667	(2.2)
Operating expenses	**$2,676**	$2,726	(1.8)
Net income after dividends on preferred stock	**$387**	$420	(7.9)
Operating Data:			
Kilowatt-hour sales *(in millions)*:			
Retail	**49,338**	52,068	(5.2)
Sales for resale - non-affiliates	**15,278**	14,848	2.9
Sales for resale - affiliates	**8,843**	5,369	64.7
Total	**73,459**	72,285	1.6
Customers served at year-end *(in thousands)*	**1,342**	1,331	0.8
Peak-hour demand *(in megawatts)*	**10,241**	11,019	(7.1)
Capitalization Ratios *(percent)*:			
Common stock equity	**42.9**	43.9	
Preferred stock	**4.1**	4.4	
Company obligated mandatorily redeemable preferred securities	**4.5**	4.8	
Long-term debt	**48.5**	46.9	
Return on Average Common Equity *(percent)*	**11.89**	13.58	

On April 26, 2001, the Board of Directors of Alabama Power Company elected Charles D. McCrary as President and Chief Operating Officer, officially signaling the beginning of a transition in leadership at the Company. With this action, Mr. McCrary, former Southern Company Chief Production Officer and President of Southern Company Generation and Energy Marketing, became the tenth President in the 96-year history of Alabama Power Company. On this same date, Elmer B. Harris, who had served as President and Chief Executive Officer since March 1989, assumed the role of Chairman and CEO.

As the brief transition period neared its completion, on October 25, 2001, Mr. McCrary relinquished the role of Chief Operating Officer and was elected Chief Executive Officer of the Company, while also retaining the title of President. Mr. Harris remained as Chairman of the Board until his retirement from the Company on January 11, 2002, following 44 years of service to Alabama Power Company and Southern Company.

BOARD OF DIRECTORS
ALABAMA POWER COMPANY

LETTER TO INVESTORS

Alabama Power Company 2001 Annual Report

The true strength of a company is demonstrated, not in ideal times, but during times of challenge. In 2001, Alabama Power Company showed its strength and stability, fulfilling its commitments to our customers, employees, shareholders and communities, even as the national economy faltered.

Even though a slowing economy and mild summer temperatures resulted in decreased usage of electricity in 2001 and thus decreased revenues, our shareholders did not suffer. The operating efficiencies implemented to meet our goals in 2001 should result in an even more robust performance in the future, as the national economy improves.

We also met the expectations of our customers in 2001 by exceeding our previous service-reliability record and maintaining low prices. Thanks to our excellent transmission and distribution system, electric service was available to customers 99.96 percent of the time. Alabama Power Company ranked in the top quartile in customer service in 2001, and our customers continued to pay prices that are well below the national average.

Alabama Power Company is planning ahead to ensure that our customers continue to enjoy affordable, reliable service. We continue to use a diverse fuel mix -- coal, hydro, oil, natural gas and nuclear -- to run our plants. The diverse fuel mix gives us the flexibility to keep our costs down when fuel costs rise. Furthermore, we are continuing to make arrangements for increased generating capacity in order to meet customer demand in the future.

Alabama Power Company's commitment to our customers includes a desire to make the state a great place to live, work and do business. We are dedicated to making every kilowatt-hour of electricity we produce cleaner, on average, than the one before. We continue to be a leader in developing technology to protect the environment. In 2001, Alabama Power Company successfully tested groundbreaking mercury-reduction technology at our Plant Gaston. We also tested switchgrass as a fuel at Plant Gadsden and our facility in Wilsonville continues to develop new ways to burn coal cleaner.

No matter how much the utility business may change, we believe the key to success will always be the same: Make every decision with the best interest of your customer, shareholder and employees in mind. Take every action based upon the highest standards of ethics and integrity. Our business may change, yet these beliefs are constant.

Solid values, a strong commitment to our customers and sound business strategies allowed us to successfully face the challenges of 2001 and they allow us to move into the future in a position of strength.

Sincerely,

Charles D. McCrary
President and Chief Executive Officer
March 22, 2002

MANAGEMENT'S REPORT

Alabama Power Company 2001 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 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 Alabama Power Company in conformity with accounting principles generally accepted in the United States.

Charles D. McCrary
President
and Chief Executive Officer

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

February 13, 2002

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, 2001 and 2000, and the related statements of income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

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

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

Arthur Andersen LLP

Birmingham, Alabama
February 13, 2002

RESULTS OF OPERATIONS

Earnings

Alabama Power Company's 2001 net income after dividends on preferred stock was $387 million, representing a $33 million (7.9 percent) decrease from the prior year. This decline is primarily attributable to a decrease in territorial energy sales as a result of an economic downturn and milder temperatures.

In 2000 earnings were $420 million, representing a 5 percent increase from the prior year. This improvement was primarily attributable to an increase in territorial sales partially offset by increased non-fuel operating expenses.

The return on average common equity for 2001 was 11.89 percent compared to 13.58 percent in 2000 and 13.85 percent in 1999.

Revenues

Operating revenues for 2001 were $3.6 billion, reflecting a decrease from 2000. The following table summarizes the principal factors that have affected operating revenues for the past two years:

	Amount	Increase (Decrease) From Prior Year	
	2001	**2001**	2000
		(in thousands)	
Retail --			
Base revenues	**$2,033,814**	**$ (75,125)**	$ 80,264
Fuel cost recovery and other	**713,859**	**(129,909)**	61,326
Total retail	**2,747,673**	**(205,034)**	141,590
Sales for resale --			
Non-affiliates	**485,974**	**24,244**	46,353
Affiliates	**245,189**	**78,970**	73,780
Total sales for resale	**731,163**	**103,214**	120,133
Other operating revenues	**107,554**	**20,749**	20,264
Total operating revenues	**$3,586,390**	**$ (81,071)**	$281,987
Percent change		**(2.21)%**	8.33%

Retail revenues of $2.7 billion in 2001 decreased $205 million (6.9 percent) from the prior year, compared with an increase of $142 million (5 percent) in 2000. The primary contributors to the decrease in revenues in 2001 were the negative impact of milder temperatures on energy sales, an economic downturn in the Company's service territory, and a decrease in fuel revenues. Fuel revenues have no effect on net income because they represent the recording of revenues to offset fuel expenses. Fuel rates billed to customers are designed to fully recover fluctuating fuel costs over a period of time. Lower natural gas prices, an increased fuel rate, and increased hydro production combined with decreased costs of purchased power have resulted in a $154 million (65 percent) reduction in under-recovered fuel costs at December 31, 2001 compared with the prior year. The Company expects to continue to reduce the balance of $83 million during 2002.

Other operating revenues in 2001 increased $21 million (23.9 percent) over 2000. This increase is primarily attributed to increased steam sales in conjunction with the operation of the Company's co-generation facilities, fuel sales, and rent from electric property. Since co-generation steam revenues are generally offset by fuel expenses, these revenues did not have a significant impact on earnings.

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.

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:

	2001	2000	1999
		(in millions)	
Capacity	**$125**	$127	$122
Energy	**134**	128	112
Total	**$259**	$255	$234

Capacity revenues from non-affiliates were relatively unchanged in 2001 compared to the prior two years. There are no scheduled declines in capacity until the termination of the contracts in 2010.

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

Kilowatt-hour (KWH) sales for 2001 and the percent change by year were as follows:

	KWH	Percent Change	
	2001	**2001**	2000
	(millions)		
Residential	**15,881**	**(5.3)%**	6.8%
Commercial	**12,799**	**(1.5)**	5.5
Industrial	**20,460**	**(7.4)**	0.7
Other	**198**	**(3.9)**	2.3
Total retail	**49,338**	**(5.2)**	3.8
Sales for resale -			
Non-affiliates	**15,278**	**2.9**	19.4
Affiliates	**8,843**	**64.7**	6.7
Total	**73,459**	**1.6**	6.9

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

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

Expenses

In 2001 total operating expenses of $2.7 billion were down $50 million or 1.8 percent compared with 2000. This decline is mainly due to an $18 million net decrease in fuel and purchased power costs and a $56 million decrease in non-production operation and maintenance expenses, offset by a $19 million increase in depreciation. Fuel expenses, including purchased power, are offset by fuel revenues and have no effect on net income.

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.

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:

	2001	2000	1999
Total generation (billions of KWHs)	**68**	65	63
Sources of generation (percent) --			
Coal	**64**	72	72
Nuclear	**18**	19	20
Hydro	**6**	3	5
Oil & Gas	**12**	6	3
Average cost of fuel per net KWH generated (cents) --	**1.56**	1.54	1.44

In 2001, total fuel and purchased power costs of $1.3 billion decreased $18 million (1.4 percent), while total energy sales increased 1,174 million kilowatt hours (1.6 percent) compared with the amounts recorded in 2000. Fuel and purchased power costs in 2000 increased $183 million (16 percent) compared to 1999.

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 2001 purchased power transactions from non-affiliates decreased $20 million (12 percent) due to the addition in May 2001 of a combined cycle unit and an 82 percent increase in hydro generation compared to the previous year. The hydro generation increase occurred from greater stream flows in 2001 compared to the previous year.

The 6 percent decrease in other operation expense in 2001 as compared to 2000 is primarily due to a decrease in administrative and general expenses, which can be mainly attributed to insurance refunds.

The 8.5 percent decrease in maintenance expense in 2001 as compared to 2000 is primarily due to a decrease in power production expense as a result of timing of maintenance for steam power generation facilities. 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.

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

Total net interest and other charges increased $10 million (4.0 percent) in 2001. The increase reflected a decrease in Allowance for Funds Used During Construction (AFUDC) resulting in a smaller credit to interest expense than was recorded in 2000. Total net interest and other charges increased $19 million (7.9 percent) in 2000 primarily from an increase in interest on long-term debt offset by an increase in AFUDC, which resulted in a larger credit to interest expense.

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

General

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

demand, and the rate of economic growth in the Company's service area.

Assuming normal weather, sales to retail customers are projected to grow approximately 2.4 percent annually on average during 2002 through 2006.

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

Rates 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. The rates also provide for adjustments to recognize the placing of new generating facilities into retail service under Rate CNP (Certificated New Plant). Effective July 2001, the Company's retail rates were adjusted by 0.6 percent under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001. Most recently, a 2 percent increase in retail rates was effective in October 2001, in accordance with the Rate Stabilization Equalization plan. See Note 3 to the financial statements under "Retail Rate Adjustment Procedures" for additional information.

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 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 wholesale generating facilities, which were sold to Southern Power in June 2001 and are under construction in Autaugaville, Alabama. All of the 615 megawatts will be delivered beginning 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 beginning in 2003 while the remaining half is scheduled for delivery beginning in 2004. Rate CNP will adjust retail rates when the contracted capacity delivery begins.

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash income of approximately $57 million in 2001. Future pension income is dependent on several factors including trust earnings and changes to the plan. For the Company, pension income is a component of the regulated rates and does not have a significant effect on net income. For more information see Note 2 to the financial statements.

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, regulations, and litigation could affect earnings if such costs are not fully recovered. The Clean Air Act and other important environmental items are discussed later under "Environmental Matters."

Industry Restructuring

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the primary agents of change has been the Energy Policy Act of 1992 (Energy Act). The Energy Act allows independent power producers (IPPs) to access a utility's transmission network in order to sell electricity to other utilities. This enhances the incentive for IPPs to build 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 recent 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 energy crisis that occurred in California. As a result of that crisis, many states have either discontinued or delayed implementation of initiatives involving retail deregulation.

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.

The Company had 1,230 megawatts of wholesale generating facilities under construction in 2001 at Autaugaville, Alabama. In June 2001 the Company sold this project to Southern Power Company, a new Southern Company subsidiary formed in 2001 to construct, own, and manage wholesale generating assets in the Southeast. The Company has entered into a purchased power agreement with Southern Power, through May 2010, for half of the capacity of these generating facilities.

In December 1999, the Federal Energy Regulatory Commission (FERC) issued its final ruling on Regional Transmission Organizations (RTOs). The order encouraged utilities owning transmission systems to form RTOs on a voluntary basis. Southern Company and its operating companies, including the Company, have submitted a series of status reports informing the FERC of progress toward the development of a Southeastern RTO. In these status reports, Southern Company explained that it is developing a for-profit RTO known as SeTrans with a number of non-jurisdictional cooperative and public power entities. Recently, Entergy Corporation and Cleco Power joined the SeTrans development process. In January 2002 the sponsors of SeTrans held a public meeting to form a Stakeholder Advisory Committee, which will participate in the development of the RTO. Southern Company continues to work with the other sponsors to develop the SeTrans RTO. The creation of SeTrans is not expected to have a material impact on the Company's financial statements. The outcome of this matter cannot now be determined.

Accounting Standards

Critical Policy

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

New Accounting Standards

Effective January 2001, the Company adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Statement No. 133 establishes accounting and reporting standards for derivative instruments and for hedging activities. This statement 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. See Note 1 to the financial statements under "Financial Instruments" for additional information. The impact on net income in 2001 was not material. An additional interpretation of Statement No. 133 will result in a change – effective April 1, 2002 – in accounting for certain contracts related to fuel supplies that contain quantity options. These contracts will be accounted for as derivatives and marked to market. However, due to the existence of the Company's cost-based fuel recovery clause, this change is not expected to have a material impact on net income.

In June 2001 the FASB issued Statement No. 142, Goodwill and Other Intangible Assets, which establishes new accounting and reporting standards for acquired goodwill and other intangible assets and supersedes Accounting Principles Board Opinion No. 17. Statement

No. 142 addresses how intangible assets that are acquired individually or with a group of other assets (but not those acquired in a business combination) should be accounted for upon acquisition and on an ongoing basis. Goodwill and intangible assets that have indefinite useful lives will not be amortized but rather will be tested at least annually for impairment. Intangible assets that have finite useful lives will continue to be amortized over their useful lives, which are no longer limited to 40 years. The Company adopted Statement No.142 in January 2002 with no material impact on the financial statements.

Also in June 2001, the FASB issued Statement No. 143, Asset Retirement Obligations, which establishes new accounting and reporting standards for legal obligations associated with retiring assets, including decommissioning of nuclear plants. The liability for an asset's future retirement must be recorded in the period in which the liability is incurred. The cost must be capitalized as part of the related long-lived asset and depreciated over the asset's useful life. Changes in the liability resulting from the passage of time will be recognized as operating expenses. Statement No. 143 must be adopted by January 1, 2003. The Company has not yet quantified the impact of adopting Statement No. 143 on its financial statements.

FINANCIAL CONDITION

Overview

In 2001, despite significant cost control measures, the Company's earnings were adversely impacted by an economic downturn and milder temperatures. However, over the last several years the Company's financial condition has remained stable as a result of growth in retail energy sales and cost control measures combined with 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 $636 million in 2001. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, principally from earnings and non-cash charges to income such as depreciation and deferred income taxes. The Statements of Cash Flows provide additional details.

Credit Rating Risk

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

Exposure to Market Risk

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, 2001, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. Fair value of changes in energy trading contracts and year-end valuations are as follows:

	Changes During the Year
	Fair Value
	(in thousands)
Contracts beginning of year	$ 567
Contracts realized or settled	(509)
New contracts at inception	-
Changes in valuation techniques	-
Current period changes	156
Contracts end of year	$ 214

	Source of Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in thousands)		
Actively quoted	$(4,840)	$(4,801)	$(39)
External sources	5,054	5,054	-
Models and other methods	-	-	-
Contracts end of Year	$ 214	$ 253	$(39)

Also, based on the Company's overall variable rate long-term debt exposure at December 31, 2001, a near-term 100 basis point change in interest rates would not materially affect the financial statements.

For additional information, see Note 1 to the financial statements under "Financial Instruments."

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

Capital Structure

The Company's ratio of common equity to total capitalization -- including short-term debt -- was 42.8 percent in 2001, 42.2 percent in 2000, and 42.4 percent in 1999.

In August 2001, the Company issued $442 million of senior notes, the proceeds of which were used to redeem the $131.5 million outstanding principal of its First Mortgage Bonds, 9% Series due December 1, 2004 and for other corporate purposes, including the repayment of a portion of its short-term indebtedness.

Capital Requirements

Capital expenditures are estimated to be $671 million for 2002, $592 million for 2003, and $673 million for 2004. 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

In addition to the funds required for the Company's construction program, approximately $1.1 billion will be required by the end of 2004 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.

These capital requirements, lease obligations, and purchase commitments – discussed in notes 4 and 8 to the financial statements – are as follows:

	2002	2003	2004
		(in millions)	
Bonds -			
First mortgage	$ 4.5	$ -	$ -
Pollution control	-	-	-
Senior Notes	-	573.2	525.0
Leases -			
Capital	0.9	0.9	1.0
Operating	27.9	26.5	25.5
Purchase commitments -			
Fuel	795.0	794.0	801.0
Purchased Power	-	53.0	83.0

At the beginning of 2002, the Company had not used any of its available credit arrangements. Credit arrangements are as follows:

		Expires	
Total	Unused	2002	2003 & Beyond
		(in millions)	
$964	$964	$574	$390

Environmental Matters

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. Reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fired generating plants were required in two phases. Phase I compliance began in 1995.

Southern Company achieved Phase I compliance at its affected plants by primarily switching to low-sulfur coal and with some equipment upgrades. Construction expenditures for Phase I nitrogen oxide and sulfur dioxide emissions 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 the Company's total construction expenditures through 2000 by $63 million.

In December 2000, the Alabama Department of Environmental Management adopted revisions to the State Implementation Plan for meeting the one-hour ozone standard. New emission limits to comply with these requirements must be implemented in May 2003. Two generating plants will be affected in the Birmingham area. Capital expenditures for compliance with these new rules are currently estimated at approximately $240 million, of which $170 million remains to be spent.

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 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 is considering other legal challenges to these standards. A court decision is expected in the spring of 2002. If the standards are eventually upheld, implementation could be required by 2007 to 2010.

In September 1998, the EPA issued nitrogen oxide reduction rules to the states for implementation. The final rule affects 21 states, including Alabama. Compliance is required by May 31, 2004 for most states including Alabama. Capital expenditures for compliance with these new rules are currently estimated at approximately $175 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 in Atlanta, Georgia. The complaint alleges violations of the New Source Review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued to the Company a notice of violation relating to these specific facilities, as well as Plants Greene County and Gaston. In early 2000 the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and notice of violation are similar to those brought against and issued to several other electric utilities. 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. In August 2000, the U.S. District Court in Georgia granted the Company's motion to dismiss for lack of jurisdiction in Georgia. On January 12, 2001, the EPA re-filed its claims against the Company in federal district court in Birmingham, Alabama. The case has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA case involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA case could have a significant adverse impact on the Company, it is party to that case as well. The U.S. District Court in Alabama has indicated that it will revisit the issue of a continued stay in April 2002.

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. However, an adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and possibly require payment of substantial penalties. 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. This could affect future results of operations, cash flows, and possibly financial condition unless such costs can be recovered through regulated rates.

In December 2000, having completed its utility studies for mercury and other hazardous air pollutants (HAPS), the EPA issued a determination that an emission control program for mercury, and perhaps other HAPS is warranted. The program is being developed under the Maximum Achievable Control Technology provisions of the Clean Air Act, and the regulations are scheduled to be finalized by the end of 2004 with implementation to take place around 2007. 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 Regional Haze Regulations, including the BART

provisions, is ongoing in the Federal District of Columbia Circuit Court of Appeals. A court decision is expected in mid-2002.

Implementation of the final state rules for these initiatives could require substantial further reductions in nitrogen oxide and sulfur dioxide and reductions in 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.

In October 1997, the EPA issued regulations setting forth requirements for Compliance Assurance Monitoring (CAM) in its state and federal operating permit programs. These regulations were amended by the EPA in March 2001 in response to a court order resolving challenges to the rules brought by environmental groups and industry. Generally, this rule affects the operation and maintenance of electrostatic precipitators and could involve significant additional ongoing expense.

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; cooling 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 and will recognize in the financial statements costs to clean up known sites. The Company has not incurred any significant 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, 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.

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.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other Southern Company operating companies. At December 31, 2001, the Company had outstanding $10 million of commercial paper.

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," "could," "expects," "plans,"

"anticipates," "believes," "estimates," "predicts," "projects," "potential," "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 impact of fluctuations in commodity prices, interest rates, and customer demand; state and federal rate regulations; political, legal, and economic conditions and developments in the United States; internal restructuring or other restructuring options that may be pursued; potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company; the effects of and changes in economic conditions in the areas in which the Company operates; the direct or indirect effects on the Company's business resulting from the terrorist incidents on September 11, 2001, or any similar such incidents or responses to such incidents; financial market conditions and the results of financing efforts; the timing and acceptance of the Company's new product and service offerings; the ability of the Company to obtain additional generating capacity at competitive prices; weather and other natural phenomena; and other factors discussed elsewhere herein and in other reports (including 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, 2001, 2000, and 1999
Alabama Power Company 2001 Annual Report

	2001	2000	1999
		(in thousands)	
Operating Revenues:			
Retail sales	**$2,747,673**	$2,952,707	$2,811,117
Sales for resale --			
Non-affiliates	**485,974**	461,730	415,377
Affiliates	**245,189**	166,219	92,439
Other revenues	**107,554**	86,805	66,541
Total operating revenues	**3,586,390**	3,667,461	3,385,474
Operating Expenses:			
Operation --			
Fuel	**1,000,828**	963,275	855,632
Purchased power --			
Non-affiliates	**144,991**	164,881	93,204
Affiliates	**147,967**	184,014	180,563
Other	**508,264**	538,529	531,696
Maintenance	**275,510**	301,046	277,724
Depreciation and amortization	**383,473**	364,618	347,574
Taxes other than income taxes	**214,665**	209,673	204,645
Total operating expenses	**2,675,698**	2,726,036	2,491,038
Operating Income	**910,692**	941,425	894,436
Other Income (Expense):			
Interest income, net	**15,101**	16,152	15,671
Equity in earnings of unconsolidated subsidiaries (Note 5)	**4,494**	3,156	2,650
Other, net	**(8,579)**	(2,226)	(12,805)
Earnings Before Interest and Income Taxes	**921,708**	958,507	899,952
Interest and Other:			
Interest expense, net	**246,436**	235,331	217,066
Distributions on preferred securities of subsidiary (Note 8)	**24,775**	25,549	24,662
Total interest and other, net	**271,211**	260,880	241,728
Earnings Before Income Taxes	**650,497**	697,627	658,224
Income taxes (Note 7)	**248,597**	261,555	241,880
Earnings Before Cumulative Effect of Accounting Change	**401,900**	436,072	416,344
Cumulative effect of accounting change less income taxes of $215 thousand	**353**	-	-
Net Income	**402,253**	436,072	416,344
Dividends on Preferred Stock	**15,524**	16,156	16,464
Net Income After Dividends on Preferred Stock	**$ 386,729**	$ 419,916	$ 399,880

The accompanying notes are an integral part of these statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2001, 2000, and 1999
Alabama Power Company 2001 Annual Report

	2001	2000	1999
		(in thousands)	
Operating Activities:			
Net income	**$ 402,253**	$ 436,072	$ 416,344
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**437,490**	412,998	403,332
Deferred income taxes and investment tax credits, net	**(21,569)**	66,166	29,039
Other, net	**(122,651)**	(37,703)	(12,661)
Changes in certain current assets and liabilities --			
Receivables, net	**88,325**	(125,652)	33,509
Fossil fuel stock	**(38,663)**	23,967	(1,344)
Materials and supplies	**(13,025)**	(10,662)	(17,968)
Accounts payable	**(83,077)**	107,702	(38,556)
Energy cost recovery, retail	**154,320**	(69,190)	(97,869)
Other	**34,503**	23,336	5,930
Net cash provided from operating activities	**837,906**	827,034	719,756
Investing Activities:			
Gross property additions	**(635,540)**	(870,581)	(809,044)
Sales of property	**102,068**	-	-
Other	**(34,771)**	(49,414)	(72,218)
Net cash used for investing activities	**(568,243)**	(919,995)	(881,262)
Financing Activities:			
Increase (decrease) in notes payable, net	**(271,347)**	184,519	96,824
Proceeds --			
Common stock	**15,642**	-	-
Other long-term debt	**477,000**	250,000	751,650
Preferred securities	**-**	-	50,000
Capital contributions from parent company	**107,313**	204,371	204,347
Redemptions --			
First mortgage bonds	**(138,991)**	(111,009)	(470,000)
Other long-term debt	**(19,021)**	(5,987)	(104,836)
Preferred stock	**-**	-	(50,000)
Payment of preferred stock dividends	**(14,942)**	(16,110)	(15,788)
Payment of common stock dividends	**(393,900)**	(417,100)	(399,600)
Other	**(9,908)**	(951)	(15,864)
Net cash provided from (used for) financing activities	**(248,154)**	87,733	46,733
Net Change in Cash and Cash Equivalents	**21,509**	(5,228)	(114,773)
Cash and Cash Equivalents at Beginning of Period	**14,247**	19,475	134,248
Cash and Cash Equivalents at End of Period	**$ 35,756**	$ 14,247	$ 19,475
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of amount capitalized)	**$246,316**	$237,066	$229,305
Income taxes (net of refunds)	**223,961**	175,303	170,121

The accompanying notes are an integral part of these statements.

BALANCE SHEETS
At December 31, 2001 and 2000
Alabama Power Company 2001 Annual Report

Assets	2001	2000
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 35,756	$ 14,247
Receivables --		
Customer accounts receivable	281,985	337,870
Under-recovered retail fuel clause revenue	83,497	237,817
Other accounts and notes receivable	49,940	60,315
Affiliated companies	72,639	95,704
Accumulated provision for uncollectible accounts	(5,237)	(6,237)
Refundable income taxes	-	-
Fossil fuel stock, at average cost	99,278	60,615
Materials and supplies, at average cost	191,324	178,299
Other	74,640	52,624
Total current assets	883,822	1,031,254
Property, Plant, and Equipment:		
In service	13,159,560	12,431,575
Less accumulated provision for depreciation	5,309,557	5,107,822
	7,850,003	7,323,753
Nuclear fuel, at amortized cost	88,777	94,050
Construction work in progress	357,906	744,974
Total property, plant, and equipment	8,296,686	8,162,777
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries (Note 5)	44,742	38,623
Nuclear decommissioning trusts	317,508	313,895
Other	12,244	13,612
Total other property and investments	374,494	366,130
Deferred Charges and Other Assets:		
Deferred charges related to income taxes (Note 7)	334,830	345,550
Prepaid pension costs	314,100	255,256
Debt expense, being amortized	8,150	8,758
Premium on reacquired debt, being amortized	77,173	76,020
Department of Energy assessments	21,015	24,588
Other	108,031	95,772
Total deferred charges and other assets	863,299	805,944
Total Assets	$10,418,301	$10,366,105

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

BALANCE SHEETS
At December 31, 2001 and 2000
Alabama Power Company 2001 Annual Report

Liabilities and Stockholder's Equity	2001	2000
	(in thousands)	
Current Liabilities:		
Securities due within one year (Note 8)	$ 5,382	$ 844
Notes payable	9,996	281,343
Accounts payable --		
Affiliated	98,268	124,534
Other	151,705	209,205
Customer deposits	42,124	36,814
Taxes accrued --		
Income taxes	113,003	65,505
Other	19,023	19,471
Interest accrued	35,522	33,186
Vacation pay accrued	32,324	31,711
Other	93,589	97,743
Total current liabilities	600,936	900,356
Long-term debt (See accompanying statements)	3,742,346	3,425,527
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes (Note 7)	1,387,661	1,401,424
Deferred credits related to income taxes (Note 7)	202,881	222,485
Accumulated deferred investment tax credits	238,225	249,280
Employee benefits provisions	99,919	71,813
Prepaid capacity revenues (Note 6)	40,730	58,377
Other	130,214	176,559
Total deferred credits and other liabilities	2,099,630	2,179,938
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)	3,310,877	3,195,772
Total Liabilities and Stockholder's Equity	$10,418,301	$10,366,105

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

STATEMENTS OF CAPITALIZATION
At December 31, 2001 and 2000
Alabama Power Company 2001 Annual Report

		2001	2000	2001	2000
			(in thousands)	*(percent of total)*	
Long-Term Debt:					
First mortgage bonds --					
Maturity	Interest Rates				
2023 through 2024	7.30% - 7.75%	**$ 350,000**	$ 488,991		
Total first mortgage bonds		**350,000**	488,991		
Senior notes --					
Variable rate (2.28% at 1/1/02) due March 3, 2003		**167,000**	-		
5.35% due November 15, 2003		**156,200**	156,200		
7.850% due May 15, 2003		**250,000**	250,000		
7.125% due August 15, 2004		**250,000**	250,000		
4.875% due September 1, 2004		**275,000**	-		
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		**1,199,402**	1,202,581		
Total senior notes		**2,882,602**	2,443,781		
Other long-term debt --					
Pollution control revenue bonds --					
Collateralized:					
5.50% due 2024		**24,400**	24,400		
Variable rates (1.61% to 1.95% at 1/1/02) due 2015-2017		**89,800**	89,800		
Non-collateralized:					
6.69% due 2021		**50,000**	65,000		
Variable rates (1.75% to 2.05% at 1/1/02) due 2021-2031		**395,940**	360,940		
Total other long-term debt (Note 8)		**560,140**	540,140		
Capitalized lease obligations		**3,323**	4,165		
Unamortized debt premium (discount), net		**(48,337)**	(50,706)		
Total long-term debt (annual interest requirement -- $217.2 million)		**3,747,728**	3,426,371		
Less amount due within one year		**5,382**	844		
Long-term debt excluding amount due within one year		**$3,742,346**	$3,425,527	**48.5%**	46.9%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2001 and 2000
Alabama Power Company 2001 Annual Report

	2001	2000	2001	2000
		(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 (3.60% at 1/1/02)	**50,000**	50,000		
Total (annual distribution requirement -- $24.2 million)	**347,000**	347,000	**4.5**	4.8
Cumulative Preferred Stock:				
$100 par or stated value --				
4.20% to 4.92%	**47,512**	47,512		
$25 par or stated value --				
5.20% to 5.83%	**200,000**	200,000		
Auction rates -- at 1/1/02				
3.10% to 3.557%	**70,000**	70,000		
Total (annual dividend requirement -- $15.2 million)	**317,512**	317,512	**4.1**	4.4
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 6,000,000 shares				
Outstanding - 6,000,000 shares in 2001 and 5,608,955 shares in 2000				
Par value	**240,000**	224,358		
Paid-in capital	**1,850,676**	1,743,363		
Premium on Preferred Stock	**99**	99		
Retained earnings	**1,220,102**	1,227,952		
Total common stockholder's equity	**3,310,877**	3,195,772	**42.9**	43.9
Total Capitalization	**$7,717,735**	$7,285,811	**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, 2001, 2000, and 1999
Alabama Power Company 2001 Annual Report

	Common Stock	Paid-In Capital	Premium on Preferred Stock	Retained Earnings	Total
			(in thousands)		
Balance at January 1, 1999	$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
Net income after dividends on preferred stock	-	-	-	**386,729**	**386,729**
Capital contributions from parent company	-	**107,313**	-	-	**107,313**
Cash dividends on common stock	-	-	-	**(393,900)**	**(393,900)**
Issuance of common stock	**15,642**	-	-	-	**15,642**
Other	-	-	-	**(679)**	**(679)**
Balance at December 31, 2001	**$240,000**	**$1,850,676**	**$99**	**$1,220,102**	**$3,310,877**

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 operating companies, a system service company, Southern Communications Services (Southern LINC), Southern Nuclear Operating Company (Southern Nuclear), Southern Power Company (Southern Power), and other direct and indirect subsidiaries. The operating companies -- Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company -- provide electric service in four southeastern states. Contracts among the operating companies – 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 its subsidiary companies. Southern LINC provides digital wireless communications services to the operating companies and also markets these services to the public within the Southeast. Southern Nuclear provides services to Southern Company's nuclear power plants. Southern Power was established in 2001 to construct, own, and manage Southern Company's competitive generation assets and sell electricity at market-based rates in the wholesale market.

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

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

Affiliate Transactions

The Company has an agreement with the system service company under which the following services are rendered to the Company at 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 $183 million, $187 million, and $218 million during 2001, 2000, and 1999, 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 $160 million, $148 million, and $135 million during 2001, 2000, and 1999, respectively.

In 2001, the Company had under construction a 1,230 megawatt combined cycle facility in Autaugaville, Alabama. In June 2001, the Company sold this project to Southern Power Company, a new Southern Company affiliate formed in 2001 to construct, own, and manage wholesale generating assets in the Southeast.

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:

	2001	2000
	(in millions)	
Deferred income tax charges	**$ 335**	$ 346
Deferred income tax credits	**(203)**	(222)
Premium on reacquired debt	**77**	76
Department of Energy assessments	**21**	25
Vacation pay	**32**	32
Natural disaster reserve	**(12)**	(18)
Other, net	**57**	30
Total	**$ 307**	$ 269

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.

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 $58 million in 2001, $61 million in 2000, and $63 million in 1999.

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 $21 million at December 31, 2001. 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 2001, 2000, and 1999. 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 2001 and fund balances as of December 31, 2001 were:

	(in millions)
Amount expensed in 2001	**$ 18**
Accumulated provisions:	
External trust funds, at fair value	$318
Internal reserves	36
Total	$354

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 $19 million in 2001, $43 million in 2000, and $23 million in 1999. The composite rate used to determine the amount of allowance was 7.7 percent in 2001, 9.6 percent in 2000, and 8.8 percent in 1999. AFUDC, net of income tax, as a percent of net income after dividends on preferred stock was 3.3 percent in 2001, 8.4 percent in 2000, and 4.7 percent in 1999.

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

Effective January 2001, the Company adopted FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. The impact on net income was immaterial.

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 and its affiliates, through the system service company acting as their agent, enters 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 Company's bulk energy purchases and sales contracts meet the definition of a derivative under FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities. In many cases these fuel and electricity contracts qualify for normal purchase and sale exceptions under Statement No. 133 and are accounted for under the accrual method. Other contracts qualify as cash flow hedges of anticipated transactions, resulting in the deferral of related gains and losses and are recorded in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Contracts that do not qualify for the normal purchase and sale exception and that do not meet the hedge requirements are marked to market through current period income.

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

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
At December 31, 2001	**$3,744**	**$3,800**
At December 31, 2000	3,422	3,375
Preferred Securities:		
At December 31, 2001	**347**	**346**
At December 31, 2000	347	344

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, 2001, the reserve balance was $12 million.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan that covers 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 the 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 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:

	2001	2000
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	
	2001	2000
	(in millions)	
Balance at beginning of year	**$925**	$896
Service cost	**25**	23
Interest cost	**70**	65
Benefits paid	**(56)**	(51)
Actuarial gain and employee transfers	**(1)**	(8)
Amendments	**48**	-
Balance at end of year	**$1,011**	$925

	Plan Assets	
	2001	2000
	(in millions)	
Balance at beginning of year	**$1,921**	$1,647
Actual return on plan assets	**(277)**	302
Benefits paid	**(56)**	(51)
Employee transfers	**(4)**	23
Balance at end of year	**$1,584**	$1,921

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

	2001	2000
	(in millions)	
Funded status	**$ 573**	$ 996
Unrecognized transition obligation	**(15)**	(20)
Unrecognized prior service cost	**78**	36
Unrecognized net actuarial gain	**(322)**	(757)
Prepaid asset recognized in the Balance Sheets	**$ 314**	$ 255

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

	2001	2000	1999
	(in millions)		
Service cost	**$ 25**	$ 23	$ 23
Interest cost	**70**	65	58
Expected return on plan assets	**(131)**	(119)	(109)
Recognized net actuarial gain	**(22)**	(19)	(13)
Net amortization	**1**	(1)	(1)
Net pension income	**$ (57)**	$ (51)	$ (42)

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	
	2001	2000
	(in millions)	
Balance at beginning of year	**$264**	$264
Service cost	**5**	4
Interest cost	**24**	19
Benefits paid	**(18)**	(12)
Actuarial gain and employee transfers	**(13)**	(11)
Amendments	**86**	-
Balance at end of year	**$348**	$264

	Plan Assets	
	2001	2000
	(in millions)	
Balance at beginning of year	**$192**	$161
Actual return on plan assets	**(24)**	25
Employer contributions	**19**	18
Benefits paid	**(18)**	(12)
Balance at end of year	**$169**	$192

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

	2001	2000
	(in millions)	
Funded status	**$(179)**	$(72)
Unrecognized transition obligation	**45**	49
Prior service cost	**82**	-
Unrecognized net actuarial gain	**(9)**	(35)
Fourth quarter contributions	**8**	4
Accrued liability recognized in the Balance Sheets	**$ (53)**	$(54)

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

	2001	2000	1999
	(in millions)		
Service cost	$ 5	$ 4	$ 5
Interest cost	24	19	18
Expected return on plan assets	(15)	(13)	(11)
Net amortization	7	4	4
Net postretirement cost	$ 21	$ 14	$ 16

An additional assumption used in measuring the accumulated postretirement benefit obligations was a weighted average medical care cost trend rate of 9.25 percent for 2001, decreasing gradually to 5.25 percent through the year 2010, and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1 percent would affect the accumulated benefit obligation and the service and interest cost components at December 31, 2001 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$30	$26
Service and interest costs	3	2

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides a 75 percent matching contribution up to 6 percent of an employee's base salary. Total matching contributions made to the plan for the years 2001, 2000, and 1999 were $12 million, $11 million, and $10 million, respectively.

Work Force Reduction Programs

The Company has incurred costs for work force reduction programs totaling $13.0 million, $2.6 million and $5.6 million for the years 2001, 2000 and 1999, respectively. These costs were deferred and are being amortized in accordance with regulatory treatment. The unamortized balance of these costs was $11.9 million at December 31, 2001.

3. CONTINGENCIES AND REGULATORY MATTERS

General

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In the opinion of management after consultation with legal counsel, the ultimate disposition of these matters is not expected to have a material adverse effect on the Company's financial condition.

Environmental Litigation

On November 3, 1999, the Environmental Protection Agency (EPA) brought a civil action in U.S. District Court in Georgia against the Company. The complaint alleges violations of the New Source Review provisions of the Clean Air Act with respect to coal-fired generating facilities at the Company's Plants Miller, Barry, and Gorgas. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The Clean Air Act authorizes civil penalties of up to $27,500 per day, per violation at each generating unit. Prior to January 30, 1997, the penalty was $25,000 per day.

The EPA concurrently issued to the Company a notice of violation relating to these specific facilities, as well as Plants Greene County and Gaston. In early 2000, the EPA filed a motion to amend its complaint to add the violations alleged in its notice of violation. The complaint and the notice of violation are similar to those brought against and issued to several other electric utilities. The complaint and the notice of violation allege that the Company failed to secure necessary permits or install additional pollution control equipment when performing maintenance and construction at coal burning plants constructed or under construction prior to 1978. On August 1, 2000, the U.S. District Court granted the Company's motion to dismiss for lack of jurisdiction in Georgia. On January 12, 2001, the EPA re-filed its claims against the Company in federal district court in Birmingham, Alabama.

The Company's case has been stayed since the spring of 2001, pending a ruling by the U.S. Court of Appeals for the Eleventh Circuit in the appeal of a very similar New Source Review enforcement action against the Tennessee Valley Authority (TVA). The TVA case involves many of the same legal issues raised by the actions against the Company. Because the outcome of the TVA case could have a significant adverse impact on the Company, it is a

party to that case as well. The U.S. District Court in Alabama has indicated that it will revisit the issue of a continued stay in April 2002.

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 under Rate CNP (Certificated New Plant). Both increases and decreases have been placed into effect since the adoption of these rates. Effective July 2001, the Company's retail rates were adjusted by 0.6 percent under Rate CNP to recover costs for Plant Barry Unit 7, which was placed into commercial operation on May 1, 2001. Most recently, a 2 percent increase in retail rates was effective in October 2001 in accordance with the Rate Stabilization Equalization plan. 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.

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. During the years 2001, 2000, and 1999, the Company did not record any such reductions.

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 wholesale generating facilities which were sold to Southern Power in June 2001 and are under construction in Autaugaville, Alabama. All of the 615 megawatts will be delivered beginning 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 beginning in 2003 while the remaining half is scheduled for delivery beginning in 2004. Rate CNP will adjust retail rates when the contracted capacity delivery begins.

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

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

4. COMMITMENTS

Construction Program

During 2001, the Company completed the replacement of the steam generators at Plant Farley, as well as the construction of new generating capacity at Plant Barry. 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 Company currently estimates property additions to be $671 million in 2002, $592 million in 2003, and $673 million in 2004.

In connection with the transfer of the Autaugaville construction project, the Company has assigned $71 million in vendor equipment contracts to Southern Power. While the Company could be obligated to assume responsibility for these contracts if Southern Power fails to meet these commitments, Southern Company has entered into limited keep-well arrangements whereby Southern Company would contribute funds to Southern Power either through loans or capital contributions in order to fund performance by Southern Power as equipment purchaser under certain contingencies. Southern Company has also guaranteed Southern Power obligations totaling $6.6 million for the Company's construction of transmission interconnection facilities to the plant.

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.

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, 2001 were as follows:

	Commitments		
Year	Affiliated	Non-Affiliated	Total
		(in millions)	
2002	$ -	$ -	$ -
2003	37	16	53
2004	49	34	83
2005	49	37	86
2006	49	38	87
2007 and thereafter	160	142	302
Total commitments	$344	$267	$611

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Total estimated long-term obligations at December 31, 2001, were as follows:

Year	Commitments
	(in millions)
2002	$ 795
2003	794
2004	801
2005	571
2006	512
2007 and thereafter	1,020
Total commitments	$4,493

In addition, the system service company acts as agent for the five operating companies and Southern Power with regard to natural gas purchases. Natural gas purchases (in dollars) are based on various indices at the actual time of delivery; therefore, only the volume commitments are firm. The Company's committed volumes allocated based on usage projections, as of December 31, 2001, are as follows:

Year	Natural Gas
	(MMBtu)
2002	77,365,361
2003	72,139,927
2004	45,600,417
2005	22,849,132
2006	14,808,334
2007 and thereafter	5,609,190
Total commitments	238,372,361

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

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $27.9 million in 2001, $20.9 million in 2000, and $17.8 million in 1999. At December 31, 2001, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Commitments
	(in millions)
2002	$ 27.9
2003	26.5
2004	25.5
2005	21.6
2006	14.4
2007 and thereafter	38.1
Total minimum payments	$ 154.0

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2004 and 2006, and the Company's maximum obligations are $25.7 million and $66.0 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation.

5. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of Southern Electric Generating Company (SEGCO), which owns electric generating units with a total rated capacity of 1,020 megawatts, together

with associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense and a return on equity, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice. The Company's share of expenses totaled $80 million in 2001, $85 million in 2000, and $92 million in 1999 and is included in "Purchased power from affiliates" in the Statements of Income.

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

At December 31, 2001, the capitalization of SEGCO consisted of $58 million of equity and $86 million of long-term debt on which the annual interest requirement is $2.2 million. SEGCO paid dividends totaling $0.7 million in 2001, $5.1 million in 2000, and $4.3 million in 1999 of which one-half of each was paid to the Company. SEGCO's net income was $7.5 million, $5.9 million, and $5.4 million for 2001, 2000, and 1999, respectively.

The Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2001, is as follows:

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

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

Facility	Company Investment	Accumulated Depreciation
	(in millions)	
Greene County	**$101**	**$ 49**
Plant Miller Units 1 and 2	**747**	**326**

6. LONG-TERM POWER SALES AGREEMENTS

General

The Company and the other operating companies of Southern Company have entered into long-term contractual agreements for the sale and lease 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 related to specific generating units. Because the energy is generally provided at cost under these agreements, profitability is primarily affected by capacity revenues.

Unit power from Plant Miller is being sold to Florida Power Corporation (FPC), Florida Power & Light Company (FP&L), and Jacksonville Electric Authority (JEA). Under these agreements approximately 1,237 megawatts of capacity are scheduled to be sold through 2010. The Company's capacity revenues amounted to $125 million in 2001, $127 million in 2000, and $122 million in 1999.

Alabama Municipal Electric Authority (AMEA) Capacity Contracts

In 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 (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 (1991 Contract). 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. The 1986 contract expired in July 2001, however, the payments for the 1991 contract will continue to be recognized as operating revenues and the discounts will be amortized to other interest expense as scheduled capacity is made available over the terms of the contract.

To secure AMEA's advance payments and the Company's performance obligation under the contracts, the Company issued and delivered to an escrow agent first mortgage bonds representing the maximum amount of liquidated damages payable by the Company in the event of a default under the contracts. No principal or interest is payable on such bonds unless and until a default by the Company occurs. As the liquidated damages decline, a

portion of the bond equal to the decrease is returned to the Company. At December 31, 2001, $38.1 million of the 1991 bond was held by the escrow agent under the contract.

7. INCOME TAXES

At December 31, 2001, the tax-related regulatory assets and liabilities were $335 million and $203 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:

	2001	2000	1999
	(in millions)		
Total provision for income taxes:			
Federal --			
Current	**$234**	$168	$194
Deferred	**(20)**	60	24
	214	228	218
State --			
Current	**37**	27	19
Deferred	**(2)**	7	5
	35	34	24
Total	**$249**	$262	$242

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:

	2001	2000
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,034**	$ 992
Property basis differences	**390**	405
Fuel cost adjustment	**28**	93
Premium on reacquired debt	**29**	30
Pensions	**89**	75
Other	**23**	12
Total	**1,593**	1,607
Deferred tax assets:		
Capacity prepayments	**13**	18
Other deferred costs	**14**	14
Postretirement benefits	**21**	24
Unbilled revenue	**18**	23
Other	**93**	81
Total	**159**	160
Total deferred tax liabilities, net	**1,434**	1,447
Portion included in current liabilities, net	**(47)**	(46)
Accumulated deferred income taxes in the Balance Sheets	**$1,387**	$1,401

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 2001, 2000, and 1999. At December 31, 2001, 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:

	2001	2000	1999
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.5**	3.1	2.4
Non-deductible book depreciation	**1.5**	1.4	1.6
Differences in prior years' deferred and current tax rates	**(1.3)**	(1.3)	(1.3)
Other	**(0.5)**	(0.7)	(0.9)
Effective income tax rate	**38.2%**	37.5%	36.8%

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. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

8. CAPITALIZATION

Mandatorily Redeemable Preferred Securities

Statutory business trusts formed by the Company, of which the Company owns all the common securities, have issued mandatorily redeemable 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 3.60% at January 1, 2002.

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

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 2001, the Company sold, through a public authority, $20 million of pollution control bonds, the proceeds of which were used to pay certain costs incurred in connection with the acquisition, construction, installation, and equipping of certain local district heating facilities and sewage and solid waste facilities at two of the Company's generation facilities.

Senior Notes

In August 2001 the Company issued $442 million of unsecured senior notes, the proceeds of which were used to redeem the $131.5 million outstanding principal of its First Mortgage Bonds, 9% Series due December 1, 2004 and for other corporate purposes including the repayment of a portion of its short-term indebtedness. All of the Company's senior notes are, in effect, subordinate to all secured debt of the Company, including its first mortgage bonds.

Capitalized Leases

The estimated aggregate annual maturities of capitalized lease obligations through 2006 are as follows: $0.9 million in 2002, $0.9 million in 2003, $1.0 million in 2004, $0.4 million in 2005, and $0.1 million in 2006.

Securities Due Within One Year

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

	2001	2000
	(in thousands)	
First mortgage bond maturities and redemptions	**$4,498**	$ -
Other long-term debt maturities	**884**	844
Total long-term debt due within one year	**$5,382**	$844

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.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $964 million (including $454 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds). Of these lines, $574 million expire at various times during 2002 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. The amount of commercial paper outstanding at December 31, 2001 was $10 million.

At December 31, 2001, the Company had regulatory approval to have outstanding up to $1 billion 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.

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, 2001, retained earnings of $796 million were restricted against the payment of cash dividends on common stock under terms of the mortgage indenture.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act of 1988 (the Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $9.5 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $200 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums which could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $88 million per incident for each licensed reactor it operates but not more than an aggregate of $10 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $176 million per incident but not more than an aggregate of $20 million to be paid for each incident in any one year.

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

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

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

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 $35 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power stations would be covered under their insurance. However, both companies revised their policy terms on a prospective basis to include an industry aggregate for all terrorist acts. The NEIL aggregate, which applies to all claims stemming from terrorism within a 12 month duration, is $3.24 billion plus any amounts that would be available through reinsurance or indemnity from an outside source. The ANI cap is $200 million in a policy year.

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

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

10. QUARTERLY FINANCIAL INFORMATION (Unaudited)

Summarized quarterly financial data for 2001 and 2000 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2001	**$ 850**	**$180**	**$ 70**
June 2001	**904**	**194**	**75**
September 2001	**1,061**	**362**	**180**
December 2001	**772**	**175**	**62**
March 2000	$ 746	$172	$ 68
June 2000	900	229	103
September 2000	1,137	390	209
December 2000	884	151	40

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

SELECTED FINANCIAL AND OPERATING DATA 1997-2001

Alabama Power Company 2001 Annual Report

	2001	2000	1999	1998	1997
Operating Revenues (in thousands)	**$3,586,390**	$3,667,461	$3,385,474	$3,386,373	$3,149,111
Net Income after Dividends on Preferred Stock (in thousands)	**$386,729**	$419,916	$399,880	$377,223	$375,939
Cash Dividends on Common Stock (in thousands)	**$393,900**	$417,100	$399,600	$367,100	$339,600
Return on Average Common Equity (percent)	**11.89**	13.58	13.85	13.63	13.76
Total Assets (in thousands)	**$10,418,301**	$10,366,105	$9,648,704	$9,225,698	$8,812,867
Gross Property Additions (in thousands)	**$635,540**	$870,581	$809,044	$610,132	$451,167
Capitalization (in thousands):					
Common stock equity	**$3,310,877**	$3,195,772	$2,988,863	$2,784,067	$2,750,569
Preferred stock	**317,512**	317,512	317,512	317,512	255,512
Company obligated mandatorily redeemable preferred securities	**347,000**	347,000	347,000	297,000	297,000
Long-term debt	**3,742,346**	3,425,527	3,190,378	2,646,566	2,473,202
Total (excluding amounts due within one year)	**$7,717,735**	$7,285,811	$6,843,753	$6,045,145	$5,776,283
Capitalization Ratios (percent):					
Common stock equity	**42.9**	43.9	43.7	46.1	47.6
Preferred stock	**4.1**	4.4	4.6	5.3	4.4
Company obligated mandatorily redeemable preferred securities	**4.5**	4.8	5.1	4.9	5.2
Long-term debt	**48.5**	46.9	46.6	43.7	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	**A+**	AA-	AA-	AA-	AA-
Preferred Stock -					
Moody's	**Baa1**	a2	a2	a2	a2
Standard and Poor's	**BBB+**	BBB+	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	**1,139,542**	1,132,410	1,120,574	1,106,217	1,092,161
Commercial	**196,617**	193,106	188,368	182,738	177,362
Industrial	**4,728**	4,819	4,897	5,020	5,076
Other	**751**	745	735	733	728
Total	**1,341,638**	1,331,080	1,314,574	1,294,708	1,275,327
Employees (year-end):	**6,706**	6,871	6,792	6,631	6,531

SELECTED FINANCIAL AND OPERATING DATA 1997-2001 (continued)

Alabama Power Company 2001 Annual Report

	2001	2000	1999	1998	1997
Operating Revenues (in thousands):					
Residential	**$ 1,138,499**	$1,222,509	$ 1,145,646	$ 1,133,435	$ 997,507
Commercial	**829,760**	854,695	807,098	779,169	724,148
Industrial	**763,934**	859,668	843,090	853,550	775,591
Other	**15,480**	15,835	15,283	14,523	13,563
Total retail	**2,747,673**	2,952,707	2,811,117	2,780,677	2,510,809
Sales for resale - non-affiliates	**485,974**	461,730	415,377	448,973	431,023
Sales for resale - affiliates	**245,189**	166,219	92,439	103,562	161,795
Total revenues from sales of electricity	**3,478,836**	3,580,656	3,318,933	3,333,212	3,103,627
Other revenues	**107,554**	86,805	66,541	53,161	45,484
Total	**$3,586,390**	$3,667,461	$3,385,474	$3,386,373	$3,149,111
Kilowatt-Hour Sales (in thousands):					
Residential	**15,880,971**	16,771,821	15,699,081	15,794,543	14,336,408
Commercial	**12,798,711**	12,988,728	12,314,085	11,904,509	11,330,312
Industrial	**20,460,022**	22,101,407	21,942,889	21,585,117	20,727,912
Other	**198,102**	205,827	201,149	196,647	180,389
Total retail	**49,337,806**	52,067,783	50,157,204	49,480,816	46,575,021
Sales for resale - non-affiliates	**15,277,839**	14,847,533	12,437,599	11,840,910	12,329,480
Sales for resale - affiliates	**8,843,094**	5,369,474	5,031,781	5,976,099	8,993,326
Total	**73,458,739**	72,284,790	67,626,584	67,297,825	67,897,827
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**7.17**	7.29	7.30	7.18	6.96
Commercial	**6.48**	6.58	6.55	6.55	6.39
Industrial	**3.73**	3.89	3.84	3.95	3.74
Total retail	**5.57**	5.67	5.60	5.62	5.39
Sales for resale	**3.03**	3.11	2.91	3.10	2.78
Total sales	**4.74**	4.95	4.91	4.95	4.57
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,981**	14,875	14,097	14,370	13,254
Residential Average Annual Revenue Per Customer	**$1,002.30**	$1,084.26	$1,028.76	$1,031.21	$922.21
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,153**	12,122	11,379	11,151	11,151
Maximum Peak-Hour Demand (megawatts):					
Winter	**9,300**	9,478	8,863	7,757	8,478
Summer	**10,241**	11,019	10,739	10,329	9,778
Annual Load Factor (percent)	**62.5**	59.3	59.7	62.9	62.7
Plant Availability (percent):					
Fossil-steam	**87.1**	89.4	80.4	85.6	86.3
Nuclear	**83.7**	88.3	91.0	80.2	88.8
Source of Energy Supply (percent):					
Coal	**56.8**	63.0	64.1	65.3	65.7
Nuclear	**15.8**	16.9	17.8	16.3	17.9
Hydro	**5.1**	2.9	4.7	6.9	7.5
Oil and gas	**10.7**	4.9	1.1	1.5	0.7
Purchased power -					
From non-affiliates	**4.4**	4.6	4.5	3.3	2.4
From affiliates	**7.2**	7.7	7.8	6.7	5.8
Total	**100.0**	100.0	100.0	100.0	100.0

DIRECTORS AND OFFICERS

Alabama Power Company 2001 Annual Report

Directors

Whit Armstrong
President, Chairman and CEO,
The Citizens Bank

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

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

Elmer B. Harris [1]
Chairman
Alabama Power Company

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

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

Patricia M. King
President and CEO,
King Motor Company

James K. Lowder
Chairman,
The Colonial Company

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

Charles D. McCrary *
President & CEO
Alabama Power Company

Dr. Thomas C. Meredith
Chancellor,
The University of Georgia System

Mayer Mitchell
President, Mitchell Brothers, Inc.

Dr. William V. Muse
Chancellor, East Carolina University

Robert D. Powers
President, The Eufaula Agency

Andreas Renschler
President, Mcc smart Gmbh

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

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

John Cox Webb, IV
President, Webb Lumber Company

James W. Wright
Chairman and CEO,
First Tuskegee Bank

Officers

Elmer B. Harris [1]
Chairman

Charles D. McCrary *
President & Chief Executive Officer

Michael D. Garrett [2]
Executive Vice President

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

C. Alan Martin
Executive Vice President

Steve R. Spencer[3]
Executive Vice President

Robert Holmes, Jr. [3]
Senior Vice President

Robin A. Hurst
Senior Vice President

Rodney O. Mundy
Senior Vice President & Counsel

Michael L. Scott
Senior Vice President

Jerry L. Stewart
Senior Vice President

Christopher C. Womack [4]
Senior Vice President

Art P. Beattie
Vice President & Comptroller

Willard L. Bowers [5]
Vice President

Christopher T. Bell [6]
Vice President

Marsha S. Johnson [7]
Vice President, Birmingham Division

Gerald L. Johnson [8]
Vice President

William B. Johnson [8]
Vice President

J. Bruce Jones
Vice President

Bobby J. Kerley [3]
Vice President, Southeast Division

William B. Keller
Vice President

Penny M. Manuel [3]
Vice President & Chief Information
Officer

Gordon G. Martin [6]
Vice President, Southern Division

Donald W. Reese
Vice President

Julian H. Smith, Jr.
Vice President

W. Ronald Smith
Vice President, Eastern Division

Cheryl A. Thompson
Vice President, Mobile Division

Terry H. Waters
Vice President, Western Division

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

E. Wayne Boston
Assistant Secretary and
Assistant Treasurer

J. Randy DeRieux
Assistant Treasurer

Robert Cole Giddens
Assistant Comptroller

Stuart Griffin [9]
Assistant Secretary

Ceila H. Shorts
Assistant Secretary

Cynthia H. Wilson [10]
Assistant Secretary

[1]Retired 1/02
[2]Resigned 4/01; Elected President of Mississippi Power Co. 4/01
[3]Elected 4/01
[4]Elected Senior Vice President of Georgia Power Co. 12/01
[5]Elected 1/02
[6]Elected 5/01
[7]Elected 7/01
[8]Elected 9/01
[9]Resigned 2/02
[10]Appointed 2/02

*See message from the Board of Directors

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Alabama. The Company sells electricity to more than 1.3 million customers within its service area of approximately 45,000 square miles. In 2001, retail energy sales accounted for 67 percent of the Company's total sales of 73.5 billion kilowatt-hours.

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

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

Registrar, Transfer Agent, and Dividend Paying Agent
All series except the Auction Class A Preferred Stock 1988 & 1993 Series
Southern Company Services, Inc.
Stockholder Services
P.O. Box 54250
Atlanta, GA 30308-0250
(800) 554-7626

For the Auction Class A Preferred Stock 1988 and 1993 Series
The Bank of New York
101 Barclay Street
New York, NY 10286

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

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