J. Randy DeRieux
Assistant Treasurer and
Manager —
Treasury/Finance

600 North 18th Street
Post Office Box 2641
Birmingham, Alabama 35291-0040

Tel 205.257.2454
Fax 205.257.1023

ALABAMA POWER
A SOUTHERN COMPANY

Always on.℠

April 24, 2007

100 Years. Lighting the way.

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 $30,000,000 within three months after submission of the statement. In this connection, enclosed are the following:

1. 2006 Annual Report (10-K) which includes financial statements for the calendar year 2006, together with the report on such statements by Deloitte & Touche LLP, independent public accountants;
2. Unaudited Financial Statements for the quarter ended March 31, 2007;
3. Cash Flow Projections for the period January 1, 2007 through December 31, 2007, showing that cash flow of $30,000,000 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:jm
Enclosures

cc: w/enclosures
Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. J. R. Johnson, Vice President – Plant Farley

U. S. Nuclear Regulatory Commission
Dr. W. D. Travers, Regional Administrator
Mr. R. E. Martin, NRR Project Manager - Farley
Mr. E.L. Crowe, Senior Resident Inspector – Farley

M004

ALABAMA POWER COMPANY
STATEMENT OF INCOME
(THOUSANDS OF DOLLARS)

	3 Months Ended 3/31/2007
OPERATING REVENUES:	
Revenues	$ 1,197,202
OPERATING EXPENSES:	
Operation --	
Fuel	386,072
Purchased & interchange power, net	77,352
Other	171,403
Maintenance	118,762
Depreciation & amortization	115,943
Taxes other than income taxes	72,718
Federal and State income taxes	72,544
Total Operating Expenses	1,014,794
OPERATING INCOME	182,408
OTHER INCOME (EXPENSES):	
Allowance for equity funds used during construction	6,586
Income from subsidiary	979
Other, net	212
INCOME BEFORE INTEREST CHARGES	190,185
INTEREST CHARGES:	
Interest on long-term debt	63,282
Allowance for debt funds used during construction	(3,346)
Amortization of debt discount, premium and expenses, net	3,531
Other interest charges	3,602
Net Interest Charges	67,069
NET INCOME	123,116
DIVIDENDS ON PREFERRED STOCK	8,182
NET INCOME AFTER DIVIDENDS ON PREFERRED STOCK	$ 114,934

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.

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 IV & V
(Stated in Thousands of Dollars)

ASSETS		At March 31, 2007		At March 31, 2006
UTILITY PLANT:				
Plant in service, at original cost	$	16,167,367	$	15,451,825
Less - Accumulated provision for depreciation and amortization	$	6,320,416	$	5,997,337
	$	9,846,951	$	9,454,488
Nuclear fuel, at amortized cost	$	139,202	$	126,078
Construction work in progress	$	622,445	$	523,939
	$	10,608,598	$	10,104,505
OTHER PROPERTY AND INVESTMENTS:				
Equity investments in subsidiaries	$	50,036	$	48,901
Investment in unconsolidated subsidiaries	$	9,279	$	9,279
Nuclear decommissioning trusts	$	518,629	$	476,264
Miscellaneous	$	24,991	$	22,742
	$	602,935	$	557,186
CURRENT ASSETS:				
Cash	$	16,073	$	12,651
Special Deposits	$	20	$	-
Temporary cash investments	$	-	$	110,000
Investment securities	$	-	$	-
Receivables -				
Customer accounts receivable	$	725,417	$	603,125
Other accounts and notes receivable	$	44,046	$	43,230
Affiliated companies	$	55,497	$	59,560
Accumulated provision for uncollectible accounts	$	(9,416)	$	(8,157)
Refundable income taxes	$	-	$	3,408
Fossil fuel stock, at average cost	$	162,059	$	134,612
Materials and supplies, at average cost	$	257,739	$	224,597
Allowance Inventory	$	4,735	$	12,659
Prepayments -				
Income taxes	$	25,244	$	-
Other	$	96,006	$	94,388
Other current assets - SFAS 133	$	7,809	$	24,652
Vacation pay deferred	$	46,415	$	44,985
	$	1,431,644	$	1,359,710
Debt expense, being amortized	$	44,908	$	38,924
Debt redemption expense, being amortized	$	91,778	$	99,576
Accumulated miscellaneous operating provisions	$	-	$	4,658
Prepaid pension cost	$	731,311	$	521,211
Regulatory assets	$	992,683	$	851,587
Miscellaneous	$	115,256	$	106,903
	$	1,975,936	$	1,622,859
TOTAL ASSETS	$	14,619,113	$	13,644,260

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 IV & V
(Stated in Thousands of Dollars)

CAPITALIZATION AND LIABILITIES		At March 31, 2007		At March 31, 2006
CAPITALIZATION:				
Common stock equity	$	4,105,416	$	3,769,305
Preferred stock	$	612,272	$	465,047
Company obligated mandatorily redeemable preferred securities *	$	309,279	$	309,279
Long-term debt	$	4,038,399	$	4,356,731
	$	9,065,366	$	8,900,362
CURRENT LIABILITIES:				
Preferred stock due or to be redeemed within one year	$	-	$	-
Long-term debt due or to be redeemed within one year	$	668,648	$	376,645
Notes payable to banks	$	-	$	-
Commercial paper	$	74,794	$	-
Accounts payable -				
Affiliated companies	$	128,392	$	115,264
Other	$	203,123	$	187,639
Customer deposits	$	62,735	$	58,877
Taxes accrued -				
Federal and state income	$	51,249	$	124,186
Other	$	49,675	$	50,371
Interest accrued	$	53,051	$	53,383
Accrued Interest Payable to Unconsolidated Subs	$	8,119	$	8,119
Vacation pay accrued	$	38,645	$	37,646
Miscellaneous	$	66,948	$	105,598
	$	1,405,379	$	1,117,728
DEFERRED CREDITS AND OTHER LIABILITIES:				
Accumulated deferred income taxes	$	2,137,888	$	2,052,072
Accumulated deferred investment tax credits	$	186,581	$	194,584
Asset Retirement Obligations	$	483,660	$	453,459
Prepaid capacity revenues, net	$	-	$	-
Regulatory liabilities	$	283,506	$	100,744
Accumulated miscellaneous operating provisions	$	-	$	-
Natural disaster reserve	$	16,957	$	3,698
Miscellaneous	$	1,039,776	$	821,613
	$	4,148,368	$	3,626,170
TOTAL CAPITALIZATION AND LIABILITIES	$	14,619,113	$	13,644,260

* Substantially all assets of Alabama Power Capital Trust IV & V are junior subordinate notes issued by the company. Upon redemption of such notes, the Trust securities will be mandatorily redeemable. See Note 7 to the financial statements of Alabama Power Company of the 2002 Form 10-K for further details.

4/23/2007 +

ALABAMA POWER COMPANY

Internal Cash Flow for
Joseph M. Farley Nuclear Power Station

(Thousands of Dollars)

	2006 Actual	2007 Projections
Net Income	$ 542,464	$ 597,170
Less Dividends Paid	464,918	497,034
Retained Earnings	77,546	100,136
Adjustments:		
Depreciation and Amortization	524,313	540,724
Deferred Income Taxes and Investment Tax Credits	(27,562)	39,976
Allowance for Equity Used During Construction	(18,253)	(41,525)
Total Adjustments	478,498	539,175
Internal Cash Flow	$ 556,044	$ 639,311
Average Quarterly Cash Flow	$ 139,011	$ 159,828

Percentage Ownership in all
Operating Nuclear Units:
Joseph M. Farley Units 1 and 2 — 100%

Maximum Total Contingent Liability — $ 30,000

Filename:PriceAnderson\nfcashfl

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

FORM 10-K

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2006
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
0-2429	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

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

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

Title of each class		Registrant
Common Stock, $5 par value		**The Southern Company**
Mandatorily redeemable preferred securities, $25 liquidation amount		
7.125% Trust Preferred Securities[2]		
Class A preferred, cumulative, $25 stated capital		**Alabama Power Company**
5.20% Series	5.83% Series	
5.30% Series		
Senior Notes		
5⅝% Series AA	5.875% Series II	
5⅞% Series GG	6.375% Series JJ	
Class A Preferred Stock, non-cumulative, *par* value $25 per share		**Georgia Power Company**
6⅛% Series		
Senior Notes		
5.90% Series O	6% Series R	5.70% Series X
5.75% Series T	6% Series W	5.75% Series G[5]
Mandatorily redeemable preferred securities, $25 liquidation amount		
7⅛% Trust Preferred Securities[3]		
5⅞% Trust Preferred Securities[4]		
Senior Notes		**Gulf Power Company**
5.25% Series H	5.75% Series I	
5.875% Series J		

[1] As of December 31, 2006.
[2] Issued by Southern Company Capital Trust VI and guaranteed by The Southern Company.
[3] Issued by Georgia Power Capital Trust V and guaranteed by Georgia Power Company.
[4] Issued by Georgia Power Capital Trust VII and guaranteed by Georgia Power Company.
[5] Assumed by Georgia Power Company in connection with its merger with Savannah Electric and Power Company, effective July 1, 2006.

Senior Notes	**Mississippi Power Company**
5⅝% Series E	
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value	
5.25% Series	
Mandatorily redeemable preferred securities, $25 liquidation amount	
7.20% Trust Originated Preferred Securities[6]	

Securities registered pursuant to Section 12(g) of the Act:[7]

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Class A Preferred Stock, cumulative, $100,000 stated capital			
Flexible Money Market (Series 2003A)			
Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

[6] Issued by Mississippi Power Capital Trust II and guaranteed by Mississippi Power Company.
[7] As of December 31, 2006.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	x	
Alabama Power Company	x	
Georgia Power Company	x	
Gulf Power Company		x
Mississippi Power Company		x
Southern Power Company		x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes X No __

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer
The Southern Company	X		
Alabama Power Company			X
Georgia Power Company			X
Gulf Power Company			X
Mississippi Power Company			X
Southern Power Company			X

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes __ No X (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2006: $23.8 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2007
The Southern Company	Par Value $5 Per Share	748,594,220
Alabama Power Company	Par Value $40 Per Share	12,250,000
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	1,792,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Proxy Statement relating to the 2007 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Information Statements of Alabama Power Company, Georgia Power Company and Mississippi Power Company relating to each of their respective 2007 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b) and (c) of Form 10-K.

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

Table of Contents

DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
AEC	Alabama Electric Cooperative, Inc.
AFUDC	Allowance for Funds Used During Construction
Alabama Power	Alabama Power Company
AMEA	Alabama Municipal Electric Authority
Clean Air Act	Clean Air Act Amendments of 1990
Dalton	City of Dalton, Georgia
DOE	United States Department of Energy
Duke Energy	Duke Energy Corporation
Energy Act of 1992	Energy Policy Act of 1992
Energy Act of 2005	Energy Policy Act of 2005
Energy Solutions	Southern Company Energy Solutions, Inc.
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
FP&L	Florida Power & Light Company
Gas South	Gas South, LLC, an affiliate of Cobb Electric Membership Corporation
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Hampton	City of Hampton, Georgia
Holding Company Act	Public Utility Holding Company Act of 1935, as amended
IBEW	International Brotherhood of Electrical Workers
IIC	Intercompany Interchange Contract
IPP	Independent power producer
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
JEA	Jacksonville Electric Authority
KUA	Kissimmee Utility Authority
MEAG	Municipal Electric Authority of Georgia
Mirant	Mirant Corporation
Mississippi Power	Mississippi Power Company
Moody's	Moody's Investors Service
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
PPA	Power Purchase Agreement
Progress Energy Carolinas	Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Southern Power Company

RFP	Request for Proposal
RTO	Regional Transmission Organization
RUS	Rural Utility Service (formerly Rural Electrification Administration)
S&P	Standard and Poor's, a division of The McGraw-Hill Companies
Savannah Electric	Savannah Electric and Power Company (merged into Georgia Power on July 1, 2006)
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company Gas	Southern Company Gas LLC
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
Southern Telecom	Southern Telecom, Inc.
traditional operating companies	Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company
TVA	Tennessee Valley Authority

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for Southern Company's wholesale business, retail sales growth, customer growth, storm damage cost recovery and repairs, fuel cost recovery, environmental regulations and expenditures, earnings growth, dividend payout ratios, access to sources of capital, projections for postretirement benefit trust contributions, synthetic fuel investments, financing activities, completion of construction projects, impacts of the adoption of new accounting rules, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Act of 2005, and also changes in environmental, tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, IRS audits, and Mirant matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of Southern Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- fluctuations in the level of oil prices;
- the level of production, if any, by the synthetic fuel operations at Carbontronics Synfuels Investors LP and Alabama Fuel Products, LLC for fiscal year 2007;
- 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 Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is domesticated under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all the outstanding common stock of Alabama Power, Georgia Power, Gulf Power and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

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

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930, and admitted to do business in Alabama on September 15, 1948. Effective July 1, 2006, Savannah Electric, formerly a wholly-owned subsidiary of Southern Company, was merged with and into Georgia Power.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

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

In addition, Southern Company owns all of the common stock of Southern Power, which is also an operating public utility company. Southern Power constructs, acquires and manages generation assets and sells electricity at market-based rates in the wholesale market. Southern Power is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida and Georgia on January 10, 2001 and in the State of Mississippi on January 30, 2001.

Southern Company also owns all the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Company Gas, Southern Nuclear, SCS, Southern Telecom, Southern Holdings and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Nuclear provides services to Alabama Power's and Georgia Power's nuclear plants. SCS is the system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Telecom provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses.

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

See Note 10 to the financial statements of Southern Company in Item 8 herein for additional information regarding Southern Company's segment and related information.

The registrants' Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional operating companies

The transmission facilities of each of the traditional operating companies are connected to the respective company's own generating plants and other sources of power and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO by means of heavy-duty high voltage lines. For information on Georgia Power's integrated transmission system, see "Territory Served by the Utilities" herein for additional information.

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

The IIC provides for coordinating operations of the power producing facilities of the traditional operating companies and Southern Power and the capacities available to such companies from non-affiliated sources and for the pooling of surplus energy available for interchange. Coordinated operation of the entire interconnected system is conducted through a central power supply coordination office maintained by SCS. The available sources of energy are allocated to the traditional operating companies and Southern Power to provide the most economical sources of power consistent with reliable operation. The resulting benefits and savings are apportioned among each of the companies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Intercompany Interchange Contract" of each of the registrants in Item 7 herein and Note 3 to the financial statements of Southern Company, each of the traditional operating companies and Southern Power, all under "FERC Matters – Intercompany Interchange Contract" in Item 8 herein for information on the settlement of the FERC proceeding related to the IIC.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures and other services with respect to business and operations and power pool transactions. Southern Power, SouthernLINC Wireless and Southern Telecom have also secured from the traditional operating companies certain services which are furnished at cost.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate Plant Farley and Plants Hatch and Vogtle, respectively. See "Regulation – Atomic Energy Act of 1954" herein for additional information.

Southern Power

Southern Power is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power constructs, acquires and manages generating facilities and sells the output under long-term, fixed-price capacity contracts both to unaffiliated wholesale purchasers as well as to the traditional operating companies (under PPAs approved by the respective state PSCs). Southern Power's business activities are not subject to traditional state regulation of utilities but are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation and electric transmission risks by making such risks the responsibility of the counterparties to the PPAs. However, Southern Power's overall profit will depend on the parameters of the wholesale market and its efficient operation of its wholesale generating assets. At December 31, 2006, Southern Power had 6,733 megawatts of nameplate capacity in commercial operation.

Other Business

In January 2006, Southern Company Gas sold substantially all of its assets, including natural gas inventory, accounts receivable and customer list to Gas South. See Note 3 to the financial statements of Southern Company under "Southern Company Gas Sale" in Item 8 herein for additional information.

Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Company's interest in one of the synthetic fuel entities was terminated in 2006. Synthetic fuel tax credits will no longer be available after December 31, 2007.

SouthernLINC Wireless serves Southern Company's traditional operating companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access and wireless data. Its system covers approximately 128,000 square miles in the Southeast.

These continuing efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2007 through 2009, see Note 7 to the financial statements of Southern Company, each traditional operating company and Southern Power all under "Construction Program" in Item 8 herein.

Estimated construction costs in 2007 are expected to be apportioned approximately as follows: (in millions)

	Southern Company System*	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
New generation	$ 172	$ -	$ -	$ -	$ -	$172
Environmental	1,661	505	955	171	21	-
Other generating facilities, including associated plant substations	441	175	167	30	21	47
New business	406	159	201	29	17	-
Transmission	447	104	293	11	28	-
Joint line and substation	5	-	-	5	-	-
Distribution	321	143	136	13	30	-
Nuclear fuel	116	48	68	-	-	-
General plant	342	84	103	19	29	22
	$3,911	$1,218	$1,923	$278	$146	$241

*These amounts include the traditional operating companies and Southern Power (as detailed in the table above) as well as the amounts for the other subsidiaries. See "Other Business" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; acquisition of additional generating assets; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; increasing costs of labor, equipment and materials; and cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Under Georgia law, Georgia Power is required to file an IRP for approval by the Georgia PSC. Through the IRP process, the Georgia PSC must pre-certify the construction of new power plants and new PPAs. See "Rate Matters – Integrated Resource Planning" herein for additional information.

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of Southern Company, each traditional operating company and Southern Power in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is derived predominantly from coal. Southern Power's supply of electricity is primarily fueled by natural gas. The sources of generation for the years 2004 through 2006 are shown below:

	Coal %	Nuclear %	Hydro %	Gas %	Oil %
Alabama Power					
2004	65	19	6	10	*
2005	67	19	6	8	*
2006	68	19	4	9	*
Georgia Power					
2004	76	22	2	*	*
2005	75	18	2	4	1
2006	75	18	1	6	*
Gulf Power					
2004	84	**	**	16	*
2005	86	**	**	14	*
2006	87	**	**	13	*
Mississippi Power					
2004	69	**	**	31	*
2005	70	**	**	30	*
2006	71	**	**	29	*
SEGCO					
2004	100	**	**	*	*
2005	100	**	**	*	*
2006	100	**	**	*	*
Southern Power					
2004	**	**	**	100	*
2005	**	**	**	100	*
2006	**	**	**	100	*
Southern Company system – weighted average					
2004	69	16	3	12	*
2005	71	15	3	11	*
2006	70	15	2	13	*

* Less than 0.5%. ** Not applicable.

For the traditional operating companies and SEGCO, the average costs of fuel in cents per net kilowatt-hour generated for 2004 through 2006 are shown below:

	2004	2005	2006
Alabama Power	1.69	2.02	2.27
Georgia Power	1.58	2.12	2.39
Gulf Power	2.32	2.77	3.27
Mississippi Power	2.50	3.11	3.34
SEGCO	1.60	1.69	2.12
Southern Company system – weighted average	1.89	2.39	2.64

The traditional operating companies have long-term agreements in place from which they expect to receive approximately 89% of their coal burn requirements in 2007. These agreements cover remaining terms up to nine years. In 2006, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.86% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by the Phase II acid rain requirements of the Clean Air Act. In 2006, Southern Company purchased approximately $50.8 million of sulfur dioxide and nitrogen oxide emission allowances to be used in current and future periods. As additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emission allowances and the timing of capital expenditures for emission control equipment. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" of Southern Company and each of the traditional operating companies in Item 7 herein for information on the Clean Air Act.

The Southern Company system has long-term agreements in place for its natural gas burn requirements. For 2007, the Southern Company system has contracted for 176 billion cubic feet of natural gas supply. These agreements cover remaining terms up to 12 years. In addition to gas supply, the Southern Company system has contracts in place for both firm gas transportation and storage. Management believes that these contracts provide sufficient natural gas supplies, transportation and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure" herein for additional information. Southern Power's PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

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

Alabama Power and Georgia Power have contracts with the DOE that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract. At Plants Farley and Hatch, on-site dry storage facilities are operational and can be expanded to accommodate spent fuel through the life of each plant. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability.

The Energy Act of 1992 established a Uranium Enrichment Decontamination and Decommissioning Fund, which is funded in part by a special assessment on utilities with nuclear plants, including Alabama Power and Georgia Power. This assessment was paid over a 15-year period that ended in 2006. 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. See Note 1 to the financial statements of Southern Company, Alabama Power and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Utilities

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

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

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution and sale of such electricity within the State of Georgia at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon and Rome), as well as in rural areas, and at wholesale currently to OPC, MEAG, Dalton and Hampton. This territory also includes the five-county area in eastern Georgia formerly served by Savannah Electric. See Note 3 to the financial statements of Georgia Power under "Merger" in Item 8 herein for information on the merger of Savannah Electric with and into Georgia Power.

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

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

For information relating to kilowatt-hour sales by classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each of the traditional operating companies in Item 7 herein. Also, for information relating to the sources of revenues for the Southern Company system, each of the traditional operating companies and Southern Power, reference is made to Item 6 herein.

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

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

One of these organizations, AEC, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems and other customers in south Alabama and northwest Florida. AEC owns generating units with approximately 1,776 megawatts of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. AEC's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from AEC to the extent such energy is available.

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

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

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by Mississippi Power to SMEPA.

There are 43 electric cooperative organizations operating in, or in areas adjoining, territory in the State of Georgia in which Georgia Power provides electric service at retail or wholesale. Three of these organizations obtain their power from TVA, one from Southern Power under a 15-year agreement which began in January 2005 and one from other sources. OPC has a wholesale power contract with the remaining 38 of these cooperative organizations. OPC and these cooperative organizations utilize self-owned generation, some of which is acquired and jointly-owned with Georgia Power, megawatt capacity purchases from Georgia Power under power supply agreements and other arrangements to meet their power supply obligations. Georgia Power, OPC and Georgia Systems Operations Corporation entered into a new control area compact agreement effective March 2005 which replaced previous coordination service agreements.

In April 2006, AEC began purchasing 250 megawatts of capacity from Georgia Power for a 10-year term. In January 2005, 29 electric cooperative organizations served by OPC and one served by Southern Power began purchasing a total of 700 megawatts of capacity from Georgia Power under individual contracts for 10-year terms. Also, in January 2005, the electric cooperative served by Southern Power began purchasing 25 megawatts of peaking capacity from Georgia Power under a 10-year contract. This electric cooperative began purchasing 50 megawatts of coal-fired capacity from Georgia Power beginning on April 1, 2006 and ending on December 31, 2014 and will purchase another 75 megawatts of coal-fired capacity from Georgia Power beginning June 1, 2010 and ending December 31, 2019. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

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

AMEA was organized under an act of the Alabama legislature and is comprised of 11 municipalities. In December 2001, Alabama Power entered into a power sales agreement with AMEA which began on January 1, 2006. Under this contract, AMEA supplies 70 to 95 megawatts of power from its combustion turbine plant and Alabama Power serves the remainder of its member needs through 2010. Beginning in 2011, the amount of power supplied to AMEA by Alabama Power is fixed at 2010 levels and AMEA has the option to seek other suppliers for its incremental growth needs through 2015, at which time the contract terminates.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG, which was established by a Georgia state statute in 1975. MEAG serves these requirements from self-owned generation facilities, some of which are acquired and jointly-owned with Georgia Power, power purchased from Georgia Power and purchases from other resources. In 1997, a pseudo scheduling and services agreement was implemented between Georgia Power and MEAG. Since 1977, Dalton has filled its requirements from self-owned generation facilities, some of which are acquired and jointly-owned with Georgia Power, and through purchases from Georgia Power pursuant to their partial requirements tariff. Beginning January 1, 2003, Dalton entered into a power supply agreement with Georgia Power and Southern Power pursuant to which it will purchase 134 megawatts from Georgia Power and the balance of its requirements, net of self-owned generation, from Southern Power for a 15-year term. In addition, Georgia Power serves the full requirements of Hampton's electric distribution system under a market-based contract. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

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

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for information concerning its PPAs.

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

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

Under the provisions of its franchises and concessions and the 1973 State Territorial Electric Service Act, and pursuant to the merger with Savannah Electric, Georgia Power now has the full but nonexclusive right to serve the City of Savannah, the Towns of Bloomingdale, Pooler, Garden City, Guyton, Newington, Oliver, Port Wentworth, Rincon, Tybee Island, Springfield, Thunderbolt and Vernonburg, and in conjunction with a secondary supplier, the Town of Richmond Hill. In addition, Savannah Electric was assigned certain unincorporated areas in Chatham, Effingham, Bryan, Bulloch and Screven Counties by the Georgia PSC. In connection with the merger of Savannah Electric with and into Georgia Power, the Georgia PSC approved the transfer of Savannah Electric's service territory to Georgia Power at the effective time of merger. See "Competition" herein for additional information.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 375,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Competition

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Act of 1992. The Energy Act of 1992 allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

Alabama Power currently has cogeneration contracts in effect with 10 industrial customers. Under the terms of these contracts, Alabama Power purchases excess generation of such companies. During 2006, Alabama Power purchased approximately 78 million kilowatt-hours from such companies at a cost of $3.9 million.

Georgia Power currently has contracts in effect with 10 small power producers whereby Georgia Power purchases their excess generation. During 2006, Georgia Power purchased 11 million kilowatt-hours from such companies at a cost of $2.4 million. Georgia Power has PPAs for electricity with two cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2006, Georgia Power purchased 356 million kilowatt-hours at a cost of $70.6 million from these facilities.

Also during 2006, pursuant to the merger with Savannah Electric, Georgia Power purchased energy from seven customer-owned generating facilities. Six of the seven customers provide only energy to Georgia Power. These six customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power does have a contract with the remaining customer for eight megawatts of dispatchable capacity and energy. During 2006, Georgia Power purchased a total of 48.6 million kilowatt-hours from the seven suppliers at a cost of approximately $1.9 million.

Gulf Power currently has agreements in effect with various industrial, commercial and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2006, Gulf Power purchased 9.3 million kilowatt-hours from such companies for approximately $0.5 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2006, this customer had no excess generation.

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

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

Southern Power competes with investor owned utilities, IPPs and others for wholesale energy sales in the Southeastern United States wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price and Southern Power's ability to contain costs.

Seasonality

Electric power generation is a seasonal business. At the traditional operating companies and Southern Power, the demand for power peaks during the hot summer months, with market prices also peaking at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies and Southern Power have historically sold less power, and consequently earned less income, when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs, which have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC) and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Utilities" and "Rate Matters" herein for additional information.

Federal Power Act

In July 2005, the U.S. Congress passed the Energy Act of 2005 which repealed the Holding Company Act effective February 8, 2006. The traditional operating companies, Southern Power and its generation subsidiaries and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and therefore remain subject to the rate, financial and accounting jurisdiction of the FERC under the Federal Power Act. Certain financing approvals which would have been obtained from the SEC under the repealed Holding Company Act now must be obtained from the FERC. In implementing repeal of the Holding Company Act, the FERC sought to minimize unnecessary administrative burdens and decided to retain an "at cost standard" for services rendered by system service companies such as SCS, to permit certain existing financing authorizations to remain effective without further action by the FERC and to reduce reporting requirements. In addition to its repeal of the Holding

Company Act, the Energy Act of 2005 authorized the FERC to establish regional reliability organizations authorized to enforce reliability standards, established a process for the FERC to address impediments to the construction of transmission and established clear responsibility for the FERC to prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 kilowatts and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,074,696 kilowatts.

In 2003, Georgia Power started the relicensing process for the Morgan Falls project which is located on the Chattahoochee River near Atlanta, Georgia and submitted the final license application for this facility to the FERC in February 2007. The current license for the Morgan Falls project expires in 2009. In 2007, Georgia Power expects to begin the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. The current Bartlett's Ferry license expires in 2014 and the application for a new license is expected to be submitted to the FERC in 2012. In July 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine developments expire in July and August of 2007. In 2006, Alabama Power initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Hydro Relicensing" of Alabama Power in Item 7 herein for additional information.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 kilowatt capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the period 2013-2033 in the case of Alabama Power's projects and in the period 2014-2039 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property taken, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property taken. If the FERC does not act on the new license application prior to the expiration of the existing license, the FERC is required to issue annual licenses, under the same terms and conditions of the existing license, until a new license is issued.

Atomic Energy Act of 1954

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

The NRC operating licenses for Plant Vogtle units 1 and 2 currently expire in January 2027 and February 2029, respectively. In January 2002, the NRC granted Georgia Power a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. Georgia Power plans to file an application with the NRC in June 2007 to extend the licenses for Plant Vogtle units 1 and 2 for an additional 20 years. In May 2005, the NRC granted Alabama Power a 20-year extension of the licenses for both units at Plant Farley which permits operation of units 1 and 2 until 2037 and 2041, respectively.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of each of the registrants in Item 7 herein for information on matters regarding the FERC.

Environmental Statutes and Regulations

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

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company and SEGCO. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act.

Additionally, each traditional operating company and SEGCO has incurred costs for environmental remediation of various sites. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulation – Environmental Remediation" of Southern Company and each of the traditional operating companies in Item 7 herein for information regarding environmental remediation efforts. Also, see Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power and Mississippi Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information regarding the identification of sites that may require environmental remediation.

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

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

Rate Matters

Rate Structure

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service areas. Rates for residential electric service are generally of the block type based upon kilowatt-hours used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions at the traditional operating companies. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed. Gulf Power's and Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Georgia Power is currently required to file for an adjustment to its fuel cost recovery rate no later than March 1, 2008. Alabama Power's fuel clause is adjusted as required. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

Approved environmental compliance and storm damage costs are recovered at Alabama Power, Gulf Power and Mississippi Power through cost recovery provisions approved by their respective state PSCs. Within limits approved by their respective PSCs, these rates are adjusted to reflect increases or decreases in such costs as required. Alabama Power recovers the cost of new plant and Gulf Power recovers purchased power capacity and conservation costs through cost recovery provisions which are adjusted as required to reflect increases or decreases in such costs as needed. Georgia Power continues to recover environmental compliance, storm damage and new plant costs through its base rates. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company under "Alabama Power Retail Regulatory Matters" and "Georgia Power Retail Regulatory Matters" and Note 3 to the financial statements of each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs and environmental compliance costs through rates.

Southern Power is authorized by the FERC to sell power to non-affiliates at market-based prices and to make short-term opportunity sales at market rates. Special FERC approval must be obtained with respect to a market-based contract with an affiliate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Market-Based Rate Authority" of Southern Power in Item 7 herein and Note 3 to the financial statements of Southern Power under "FERC Matters – Market-Based Rate Authority" in Item 8 herein for a discussion of rate matters.

Integrated Resource Planning

Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC must certify any new demand-side or supply-side resources. Once certified, the lesser of actual or certified construction costs and purchased power costs will be recoverable through rates.

In December 2002, the Georgia PSC certified a PPA between Duke Energy and Georgia Power for 620 megawatts for seven years that began in June 2005. K-Gen Power, LLC has replaced Duke Energy as a party to this contract.

In May 2004, the Georgia PSC ordered Georgia Power and Savannah Electric to purchase the McIntosh combined cycle generating facility from Southern Power and place it into their respective rate bases. The McIntosh resource was previously certified as a PPA by the Georgia PSC in the supply-side certification conducted in 2002 and, at the same time, the Georgia PSC also approved the de-certification of Savannah Electric's Plant Riverside, units 4 through 8, effective in May 2005. The McIntosh units produce a combined 1,240 megawatts and have been available since June 2005. Pursuant to the merger with Savannah Electric, Georgia Power now has 100% ownership of the McIntosh units. See Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans" in Item 8 herein for additional information.

Following the Georgia PSC's approval of the 2004 IRP, Georgia Power de-certified the Atkinson combustion turbine units 5A and 5B totaling approximately 80 megawatts of capacity and extended the life of the Kraft combustion turbine unit until such time as its retirement is warranted.

Georgia Power received certification of its RFP for approximately 1,000 megawatts to meet its future supply-side capacity needs for 2009 and beyond.

In January 2006, Georgia Power filed an application with the Georgia PSC to approve an amendment to Georgia Power's IRP in connection with the merger to add Savannah Electric customers and generating assets. In June 2006, the Georgia PSC approved the merger between Georgia Power and Savannah Electric. Also, the Georgia PSC approved the transfer of territory, customers, power plants and demand-side programs from Savannah Electric to Georgia Power.

In March 2006, Georgia Power issued RFPs for approximately 2,100 and 1,400 megawatts, respectively, to meet its 2010 and 2011 supply-side needs. For the 2011 RFP, Georgia Power submitted self-build proposals that compare to the market. Additionally, Georgia Power will continue a residential load management program which was certified by the Georgia PSC for up to 40 megawatts of equivalent supply-side capacity. Georgia Power will continue to utilize approximately eight megawatts of capacity from existing qualifying facilities under firm contracts and continue to add additional resources as ordered by the Georgia PSC.

On January 31, 2007, Georgia Power filed its 2007 IRP with the Georgia PSC. With the 2007 IRP and subsequent filings, Georgia Power proposes to: (1) retire the coal units at Plant McDonough and replace them with combined-cycle natural gas units; (2) gain approval for five new energy efficiency pilot programs and request that certified demand-side management programs receive similar financial treatment as supply-side options; (3) pursue up to three new renewable generation projects with a Georgia Power ownership interest; (4) establish new nuclear units as a preferred option to meet demand in the 2015/2016 timeframe; and (5) establish policy that baseload generating plants should be built by Georgia Power and should not be subject to the competitive bid process. The Georgia PSC decision on this 2007 IRP filing is expected in July 2007.

Environmental Cost Recovery Plans

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power" and "PSC Matters – Retail Rate Adjustments," respectively, of Southern Company and Alabama Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Alabama Power, under "Alabama Power Retail Regulatory Matters" and "Retail Regulatory Matters," respectively, in Item 8 herein for a discussion on Alabama PSC rate matters.

See Note 3 to the financial statements of Gulf Power under "Retail Regulatory Matters – Environmental Cost Recovery" in Item 8 herein for information on Gulf Power's environmental cost recovery.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Environmental Compliance Overview Plan" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 herein for information on Mississippi Power's environmental cost recovery.

Storm Damage Cost Recovery

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" of Southern Company, Gulf Power and Mississippi Power and "PSC Matters – Natural Disaster Cost Recovery" of Alabama Power in Item 7 herein and Note 3 to the financial statements of Southern Company, Alabama Power, Gulf Power and Mississippi Power under "Storm Damage Cost Recovery," "Retail Regulatory Matters – Natural Disaster Cost Recovery," "Retail Regulatory Matters – Storm Damage Cost Recovery" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, in Item 8 herein for a discussion of the impacts and recovery of storm damage costs related to Hurricanes Ivan, Dennis and Katrina.

Employee Relations

The Southern Company system had a total of 26,091 employees on its payroll at December 31, 2006.

	Employees at December 31, 2006
Alabama Power	6,796
Georgia Power	9,278
Gulf Power	1,321
Mississippi Power	1,270
SCS	3,737
Southern Holdings*	4
Southern Nuclear	3,216
Southern Power	**
Other	469
Total	26,091

* One of Southern Holdings' subsidiaries has 4 employees. Southern Holdings has agreements with SCS whereby all other employee services are rendered at cost.

** Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at cost.

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

Alabama Power has agreements with the IBEW on a five-year contract extending to August 15, 2009. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2008.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through October 14, 2009.

Mississippi Power has an agreement with the IBEW extending the previous contract for one year to August 16, 2007. Negotiations are expected to begin in July 2007 on a new four-year agreement.

Southern Nuclear has agreements with the IBEW on a three-year contract extending to June 30, 2008 for Plants Hatch and Vogtle and a three-year contract which is in effect through August 15, 2009 for Plant Farley. Upon notice given at least 60 days prior to these dates, negotiations may be initiated with respect to agreement terms to be effective after such dates.

The agreements also subject the terms of the pension plans for the companies discussed above to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from

those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

Risks Related to the Energy Industry

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals and certificates from the governmental agencies that regulate various aspects of their businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of fossil-fuel, hydroelectric and nuclear generating facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC. In addition, the respective state PSCs must approve the traditional operating companies' rates for retail customers. While the retail rates approved by the respective state PSCs are designed to provide for recovery of costs and a return on invested capital, there can be no assurance that a state PSC will not deem certain costs to be imprudently incurred and not subject to recovery.

Southern Company and its subsidiaries believe the necessary permits, approvals and certificates have been obtained for its existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

General Risks Related to Operation of Southern Company's Utility Subsidiaries

The regional power market in which Southern Company and its utility subsidiaries compete may have changing transmission regulatory structures, which could affect the ownership of these assets and related revenues and expenses.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. Transmission revenues are not separated from generation and distribution revenues in their approved retail rates. Since 1999, when the FERC issued final rules on RTOs, there have been a number of proceedings at FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. Under this new transmission regulatory structure, the traditional operating companies could transfer functional control (but not ownership) of their transmission facilities to an independent third party. While there are no active proceedings at FERC that would require Southern Company to participate in a RTO, current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. The financial condition, net income and cash flows of Southern Company and its utility subsidiaries could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

Certain events in the energy markets that are beyond the control of Southern Company and its subsidiaries have increased the level of public and regulatory scrutiny in the energy industry and in the capital markets. The reaction to these events may result in new laws or regulations related to the business operations or the accounting treatment of the existing operations of Southern Company and its subsidiaries which could have a negative impact on the net income or access to capital of Southern Company and its subsidiaries.

As a result of the energy crisis in California during the summer of 2001, the Enron Corporation bankruptcy, investigations by governmental authorities into energy trading activities and the August 2003 power outage in the Northeast, companies in regulated and unregulated electric utility businesses have been under an increased amount of public and regulatory scrutiny with respect to, among other things, accounting practices, financial disclosures and relationships with independent auditors. This increased scrutiny has led to substantial changes in laws and regulations affecting Southern Company and its subsidiaries, including, among others, enhanced internal control and auditor independence requirements, financial statement certification requirements, more frequent SEC reviews of financial statements and accelerated and additional SEC filing requirements. New accounting and disclosure requirements have changed the way Southern Company and its subsidiaries are required to record revenues, expenses, assets and liabilities. Southern Company expects continued regulatory focus on accounting and financial reporting issues. Future disruptions in the industry such as those described above and any additional resulting regulations may have a negative impact on the net income or access to capital of Southern Company and its subsidiaries.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs which could negatively impact the net income of Southern Company and the traditional operating companies and the value of their respective assets.

Increased competition, which may result from restructuring efforts, could have a significant adverse financial impact on Southern Company and its traditional operating companies. Increased competition could result in increased pressure to lower the cost of electricity. Any adoption in the territories served by the traditional operating companies of retail competition and the unbundling of regulated energy service could have a significant adverse financial impact on Southern Company and the traditional operating companies due to an impairment of assets, a loss of retail customers, lower profit margins, an inability to recover reasonable costs or increased costs of capital. Southern Company and the traditional operating companies cannot predict if or when they may be subject to changes in legislation or regulation, nor can Southern Company and the traditional operating companies predict the impact of these changes.

Additionally, the electric utility industry has experienced a substantial increase in competition at the wholesale level. As a result of changes in federal law and regulatory policy, competition in the wholesale electricity market has greatly increased due to a greater participation by traditional electricity suppliers, non-utility generators, IPPs, wholesale power marketers and brokers and due to the trading of energy futures contracts on various commodities exchanges. In addition, FERC rules on transmission service are designed to facilitate competition in the wholesale market on a nationwide basis by providing greater flexibility and more choices to wholesale power customers.

Potential changes to the criteria used by the FERC for approval of market-based contracts may negatively impact the traditional operating companies' and Southern Power's ability to charge market-based rates.

Each of the traditional operating companies and Southern Power have authorization from the FERC to sell power to nonaffiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based sale to an affiliate. In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period were approximately $19.7 million for the Southern Company system. In the event that FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the traditional operating companies and Southern Power may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates.

In addition, in May 2005 the FERC started an investigation to determine whether Southern Company satisfies the other three parts of FERC's market-based rate analysis: transmission market power, barriers to entry and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $55.4 million for the Southern Company system, of which $15.5 million relates to sales inside the retail service territory discussed above.

Risks Related to Environmental Regulation

Southern Company's and the traditional operating companies' costs of compliance with environmental laws are significant. The costs of compliance with future environmental laws and the incurrence of environmental liabilities could negatively impact the net income and cash flows of Southern Company, the traditional operating companies or Southern Power.

Southern Company and the traditional operating companies are subject to extensive federal, state and local environmental requirements which, among other things, regulate air emissions, water discharges and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these legal requirements requires Southern Company and the traditional operating companies to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees and permits at all of their respective facilities. These expenditures are significant and Southern Company and the traditional operating companies expect that they will increase in the future. Through 2006, Southern Company had invested approximately $3.1 billion in capital projects to comply with these requirements, with annual totals of $661 million, $423 million and $300 million for 2006, 2005 and 2004, respectively. Southern Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $1.66 billion, $1.65 billion and $1.27 billion for 2007, 2008 and 2009, respectively. Because Southern Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and Southern Company's fuel mix, the ultimate outcome cannot be determined at this time.

Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements, such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent.

If Southern Company, the traditional operating companies or Southern Power fail to comply with environmental laws and regulations, even if caused by factors beyond their control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power alleging violations of the new source review provisions of the Clean Air Act. Southern Company is a party to suits alleging its emissions of carbon dioxide, a greenhouse gas, contribute to global warming. An adverse outcome in any one of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require the 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.

Existing environmental laws and regulations may be revised or new laws and regulations related to global climate change, air quality or other environmental and health concerns may be adopted or become applicable to Southern Company, the traditional operating companies and Southern Power. Revised or additional laws and regulations could result in significant additional expense and operating restrictions on the facilities of the traditional operating companies or Southern Power or increased compliance costs which may not be fully recoverable from customers and would therefore reduce the net income of Southern Company, the traditional operating companies or Southern Power. The cost impact of such legislation would depend upon the specific requirements enacted and cannot be determined at this time.

Risks Related to Southern Company and its Business

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock at the current rate is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds for its payment obligations.

The financial performance of Southern Company and its subsidiaries may be adversely affected if its subsidiaries are unable to successfully operate their facilities.

Southern Company's financial performance depends on the successful operation of its subsidiaries' electric generating, transmission and distribution facilities. Operating these facilities involves many risks, including:

- operator error and breakdown or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- compliance with mandatory reliability standards if adopted; and
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza or other similar occurrences.

A decrease or elimination of revenues from power produced by the electric generating facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company.

The revenues of Southern Company, the traditional operating companies and Southern Power depend in

part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, or the failure to renew the PPAs, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs having initial terms of five to 15 years. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than the credit evaluation predicts. Neither Southern Power nor the traditional operating companies can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Southern Company, the traditional operating companies and Southern Power may incur additional costs or delays in the construction of new plants or environmental facilities and may not be able to recover their investment. The facilities of Southern Company, the traditional operating companies and Southern Power require ongoing capital expenditures.

Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company intends to continue its strategy of developing and constructing other new facilities, expanding existing facilities and adding environmental control equipment. The completion of these types of projects without delays or cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials and labor;
- work stoppages;
- permits, approvals and other regulatory matters;
- adverse weather conditions;
- unforeseen engineering problems;
- environmental and geological conditions;
- delays or increased costs to interconnect its facilities to transmission grids;
- unanticipated cost increases; and
- attention to other projects.

Tightening labor markets in the Southeast and increasing costs of materials have resulted in increasing cost estimates for Southern Company's subsidiaries' construction projects. If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs and reduced net income.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business model of Southern Company, the traditional operating companies and Southern Power is that generating power at central power plants achieves economies of scale and produces power at relatively low cost. There are other technologies that produce power, most notably fuel cells, microturbines, windmills and solar cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central power station electric production. If this were to happen and if these technologies achieved economies of scale, the market share of Southern Company, the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. Changes in technology could also alter the channels through which retail electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies or Southern Power.

Operation of nuclear facilities involves inherent risks, including environmental, health, regulatory, terrorism and financial risks that could result in fines or the

closure of Southern Company's nuclear units owned by Alabama Power or Georgia Power, and which may present potential exposures in excess of insurance coverage.

Alabama Power owns two nuclear units and Georgia Power holds undivided interests in, and contracts for operation of, four nuclear units. These six units are operated by Southern Nuclear and represent approximately 3,680 megawatts, or 9.1%, of Southern Company's generation capacity as of December 31, 2006. These nuclear facilities are subject to environmental, health and financial risks such as on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities and the threat of a possible terrorist attack. Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or new regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power and Southern Company have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult or impossible to predict.

The generation and energy marketing operations of Southern Company, the traditional operating companies and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies' and Southern Power's revenues and increase costs.

The generation and energy marketing operations of Southern Company, the traditional operating companies and Southern Power are subject to changes in power prices or fuel costs, which could increase the cost of producing power or decrease the amount Southern Company, the traditional operating companies and Southern Power receive from the sale of power. The market prices for these commodities may fluctuate over relatively short periods of time. Southern Company, the traditional operating companies and Southern Power attempt to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil and other fuels used in the generation facilities of the traditional operating companies and Southern Power including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors or third party providers;
- the financial condition of market participants;
- the economy in the service territory and in general, including the impact of economic conditions on industrial and commercial demand for electricity;
- natural disasters, wars, embargos, acts of terrorism and other catastrophic events; and
- federal, state and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

As a result of increasing fuel costs, the traditional operating companies have accrued significant underrecovered fuel cost balances. In addition, Gulf Power and Mississippi Power have significant deficit balances in their storm cost recovery reserves as a result of Hurricanes Ivan, Dennis and Katrina. The traditional operating companies may experience similar deficit balances following future storms. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating companies and Southern Company.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures and forwards, to manage their commodity and financial market risks and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium and fuel oil, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majuere events or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for much of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

In addition, Southern Power in particular, and the traditional operating companies to a lesser extent, are dependent on natural gas for a portion of their electric generating capacity. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed. For example, in connection with the 2005 hurricanes in the Gulf of Mexico, production and distribution of natural gas was limited for a period of time, resulting in shortages and significant increases in the price of natural gas. In addition, world market conditions for fuels, including the policies of the Organization of Petroleum Exporting Countries, can impact the price and availability of natural gas.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation capabilities.

Through the traditional operating companies and Southern Power, Southern Company is currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed Southern Company's available generation capacity. Market or competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation capabilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover any of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and Southern Company.

The operating results of Southern Company, the traditional operating companies and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis.

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies and Southern Power have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, available cash and borrowing ability of Southern Company, the traditional operating companies and Southern Power.

Mirant and The Official Committee of Unsecured Creditors of Mirant Corporation have filed a claim against Southern Company seeking substantial monetary damages in connection with transfers made by Mirant to Southern Company prior to the Mirant spin-off.

In July 2003, Mirant filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code. In January 2006, Mirant's plan of reorganization became effective, and Mirant emerged from bankruptcy.

In 2005, Mirant, as debtor in possession, and The Official Committee of Unsecured Creditors of Mirant Corporation filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006 and May 2006. The third amended complaint (the complaint) alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company prior to the spin-off. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach fiduciary duties to its creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under theories of restitution, unjust enrichment, and alter ego. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7 to the financial statements of Southern Company in Item 8 herein) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in June 2006.

On January 10, 2006, the U.S. District Court for the Northern District of Texas granted Southern Company's motion to withdraw this action from the Bankruptcy Court and, on February 15, 2006, granted Southern Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia. On May 19, 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts of the complaint. On December 11, 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims are barred; all other claims in the complaint may proceed. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. However, the final outcome of this matter cannot now be determined.

IRS challenges to Southern Company's income tax deductions taken in connection with four international leveraged lease transactions could result in the payment of substantial additional interest and penalties and could materially impact Southern Company's cash flow and net income.

Southern Company participates in four international leveraged lease transactions and receives federal income tax deductions for depreciation and amortization, as well as interest on related debt. In connection with its audit of Southern Company's tax returns for 1996 through 2001, the IRS proposed to disallow Southern Company's tax losses related to one international leveraged lease (a lease-in-lease-out, or LILO) transaction. In February 2005, Southern Company reached a negotiated settlement with the IRS relating to this matter, which is now final.

In connection with its audit of 2000 and 2001, the IRS also challenged Southern Company's deductions related to three other international lease (sale-in-lease-out, or SILO) transactions. In the third quarter 2006, Southern Company paid the full amount of the disputed tax and the applicable interest on the SILO issue for tax years 2000-2001 and filed a claim for refund which has been denied by the IRS. The disputed tax amount is $79 million and the related interest is approximately $24 million for these tax years. This payment, and the subsequent IRS disallowance of the refund claim, closed the issue with the IRS and Southern Company plans to proceed with litigation. The IRS has also raised the SILO issues for tax years 2002 and 2003. The estimated amount of disputed tax and interest for these years is approximately $83 million and $15 million, respectively. The tax and interest for these tax years was paid to the IRS in the fourth quarter 2006. Southern Company has accounted for both payments in 2006 as deposits, as management believes no additional tax or interest liabilities have been incurred.

Although the payment of the tax liability did not affect Southern Company's results of operations under accounting standards in effect through December 31, 2006, it did impact cash flow. For tax years 2000 through 2006, Southern Company has claimed $284 million in tax benefits related to these SILO transactions challenged by the IRS. Southern Company believes these transactions are valid leases for U.S. tax purposes and thus the related deductions are allowable. Southern Company will continue to defend this position through administrative appeals or litigation. The ultimate outcome of these matters cannot now be determined.

In July 2006, the FASB released new interpretations for the accounting for both leveraged leases and uncertain tax positions that were adopted January 1, 2007. For the LILO transaction settled with the IRS in February 2005, the leveraged leases accounting interpretation requires that Southern Company recognize a cumulative effect reduction to beginning 2007 retained earnings of approximately $17 million at adoption and change the timing of income recognized under the lease.

For the SILO transactions which are the subject of pending litigation, Southern Company is continuing to evaluate the impact of the new interpretations but estimates that the reduction to retained earnings in 2007 could be approximately $115 million to $135 million. The impact on Southern Company's net income of these accounting interpretations would also be dependent on the outcome of the pending litigation or changes in assumptions related to uncertain tax positions but could be significant and potentially material.

Risks Related to Market and Economic Volatility

The business of Southern Company, the traditional operating companies and Southern Power is dependent on their ability to successfully access capital markets. The inability of Southern Company, any traditional operating company or Southern Power to access capital may limit its ability to execute its business plan or pursue improvements and make acquisitions that Southern Company, the traditional operating companies or Southern Power may otherwise rely on for future growth.

Southern Company, the traditional operating companies and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company or Southern Power is not able to access capital at competitive rates, its ability to implement its business plan or pursue improvements and make acquisitions that Southern Company, the traditional operating companies or Southern Power may otherwise rely on for future growth will be limited. Each of Southern Company, the traditional operating companies and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of the credit rating of Southern Company, any traditional operating company or Southern Power may increase its cost of borrowing or adversely affect its ability to raise capital through the issuance of securities or other borrowing arrangements. Such disruptions could include:

- an economic downturn;
- the bankruptcy of an unrelated energy company;
- capital market conditions generally;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies;
- war or threat of war; or
- the overall health of the utility industry.

Southern Company, the traditional operating companies and Southern Power are subject to risks associated with a changing economic environment, including their ability to obtain insurance, the financial stability of their respective customers and their ability to raise capital.

The threat of terrorism and the related military action by the United States continue to affect the nation's economy and financial markets. The insurance industry has also been disrupted by these events as well as recent hurricane activity on the Gulf Coast. The availability of insurance covering risks Southern Company, the traditional operating companies, Southern Power and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies and Southern Power are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. Any economic downturn or disruption of financial markets could constrain the capital available to Southern Company's, the traditional operating companies' and Southern Power's industry and could reduce access to funding for the respective operations of Southern

Company, the traditional operating companies and Southern Power, as well as the financial stability of their respective customers and counterparties. These factors could adversely affect Southern Company's subsidiaries' ability to achieve energy sales growth, thereby decreasing Southern Company's level of future net income.

Certain of the traditional operating companies have substantial investments in the Gulf Coast region which can be subject to major storm activity. The ability of the traditional operating companies to recover costs and replenish reserves in the event of a major storm, other natural disaster, terrorist attack or other catastrophic event generally will require regulatory action. Additionally, storm damage may affect the availability and cost of insurance to these traditional operating companies.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In September 2004, Hurricane Ivan hit the Gulf coast of Florida and Alabama, causing significant damage to the service areas of Alabama Power and Gulf Power. In July and August 2005, Hurricanes Dennis and Katrina, respectively, hit the Gulf coast of the United States and caused significant damage in the service areas of Gulf Power, Alabama Power and Mississippi Power. In each case, costs to the respective traditional operating companies exceeded their respective storm cost reserves and insurance coverage and were subsequently approved for recovery by their respective state PSCs. In the event a traditional operating company experiences a natural disaster, terrorist attack or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's results of operations and/or cash flows.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties – The Electric Utilities

The traditional operating companies, Southern Power and SEGCO, at December 31, 2006, owned and/or operated 34 hydroelectric generating stations, 34 fossil fuel generating stations, three nuclear generating stations and 12 combined cycle/cogeneration stations. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
FOSSIL STEAM		
Gadsden	Gadsden, AL	120,000
Gorgas	Jasper, AL	1,221,250
Barry	Mobile, AL	1,525,000
Greene County	Demopolis, AL	300,000 (2)
Gaston Unit 5	Wilsonville, AL	880,000
Miller	Birmingham, AL	2,532,288 (3)
Alabama Power Total		6,578,538
Bowen	Cartersville, GA	3,160,000
Branch	Milledgeville, GA	1,539,700
Hammond	Rome, GA	800,000
Kraft	Port Wentworth, GA	281,136
McDonough	Atlanta, GA	490,000
McIntosh	Effingham County, GA	163,117
McManus	Brunswick, GA	115,000
Mitchell	Albany, GA	125,000
Scherer	Macon, GA	750,924 (4)
Wansley	Carrollton, GA	925,550 (5)
Yates	Newnan, GA	1,250,000
Georgia Power Total		9,600,427
Crist	Pensacola, FL	970,000
Daniel	Pascagoula, MS	500,000 (6)
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Scherer Unit 3	Macon, GA	204,500 (4)
Gulf Power Total		2,059,500
Daniel	Pascagoula, MS	500,000 (6)
Eaton	Hattiesburg, MS	67,500
Greene County	Demopolis, AL	200,000 (2)
Sweatt	Meridian, MS	80,000
Watson	Gulfport, MS	1,012,000
Mississippi Power Total		1,859,500
Gaston Units 1-4	Wilsonville, AL	
SEGCO Total		1,000,000 (7)
Total Fossil Steam		21,097,965
NUCLEAR STEAM		
Farley	Dothan, AL	
Alabama Power Total		1,720,000
Hatch	Baxley, GA	899,612 (8)
Vogtle	Augusta, GA	1,060,240 (9)
Georgia Power Total		1,959,852
Total Nuclear Steam		3,679,852

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
COMBUSTION TURBINES		
Greene County	Demopolis, AL	
Alabama Power Total		720,000
Boulevard	Savannah, GA	59,100
Bowen	Cartersville, GA	39,400
Intercession City	Intercession City, FL	47,667 (10)
Kraft	Port Wentworth, GA	22,000
McDonough	Atlanta, GA	78,800
McIntosh Units 1 through 8	Effingham County, GA	640,000
McManus	Brunswick, GA	481,700
Mitchell	Albany, GA	118,200
Robins	Warner Robins, GA	158,400
Wansley	Carrollton, GA	26,322
Wilson	Augusta, GA	354,100
Georgia Power Total		2,025,689
Lansing Smith Unit A	Panama City, FL	39,400
Pea Ridge Units 1-3	Pea Ridge, FL	15,000
Gulf Power Total		54,400
Chevron Cogenerating Station	Pascagoula, MS	147,292 (11)
Sweatt	Meridian, MS	39,400
Watson	Gulfport, MS	39,360
Mississippi Power Total		226,052
Dahlberg	Jackson County, GA	756,000
DeSoto	Arcadia, FL	343,760
Oleander	Cocoa, FL	628,400
Rowan	Salisbury, NC	455,250
Southern Power Total		2,183,410
Gaston (SEGCO)	Wilsonville, AL	19,680 (7)
Total Combustion Turbines		5,229,231
COGENERATION		
Washington County	Washington County, AL	123,428
GE Plastics Project	Burkeville, AL	104,800
Theodore	Theodore, AL	236,418
Alabama Power Total		464,646
COMBINED CYCLE		
Barry	Mobile, AL	
Alabama Power Total		1,070,424
McIntosh Units 10&11	Effingham County, GA	
Georgia Power Total		1,318,920
Smith	Lynn Haven, FL	
Gulf Power Total		545,500
Daniel (Leased)	Pascagoula, MS	
Mississippi Power Total		1,070,424

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
Franklin	Smiths, AL	1,198,360
Harris	Autaugaville, AL	1,318,920
Rowan	Salisbury, NC	530,550
Stanton Unit A	Orlando, FL	428,649 (12)
Wansley	Carrollton, GA	1,073,000
Southern Power Total		4,549,479
Total Combined Cycle		8,554,747
HYDROELECTRIC FACILITIES		
Bankhead	Holt, AL	53,985
Bouldin	Wetumpka, AL	225,000
Harris	Wedowee, AL	132,000
Henry	Ohatchee, AL	72,900
Holt	Holt, AL	46,944
Jordan	Wetumpka, AL	100,000
Lay	Clanton, AL	177,000
Lewis Smith	Jasper, AL	157,500
Logan Martin	Vincent, AL	135,000
Martin	Dadeville, AL	182,000
Mitchell	Verbena, AL	170,000
Thurlow	Tallassee, AL	81,000
Weiss	Leesburg, AL	87,750
Yates	Tallassee, AL	47,000
Alabama Power Total		1,668,079
Barnett Shoals (Leased)	Athens, GA	2,800
Bartletts Ferry	Columbus, GA	173,000
Goat Rock	Columbus, GA	38,600
Lloyd Shoals	Jackson, GA	14,400
Morgan Falls	Atlanta, GA	16,800
North Highlands	Columbus, GA	29,600
Oliver Dam	Columbus, GA	60,000
Rocky Mountain	Rome, GA	215,256 (13)
Sinclair Dam	Milledgeville, GA	45,000
Tallulah Falls	Clayton, GA	72,000
Terrora	Clayton, GA	16,000
Tugalo	Clayton, GA	45,000
Wallace Dam	Eatonton, GA	321,300
Yonah	Toccoa, GA	22,500
6 Other Plants		18,080
Georgia Power Total		1,090,336
Total Hydroelectric Facilities		2,758,415
Total Generating Capacity		41,784,856

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.

(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(4) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

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

(6) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.

(7) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

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

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

(10) Capacity shown represents 33⅓% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.

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

(12) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(13) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

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

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2006, the unamortized portion of this cost was approximately $26.2 million.

The all-time maximum demand on the traditional operating companies, Southern Power and SEGCO was 35,889,900 kilowatts and occurred on August 7, 2006. This amount excludes demand served by capacity retained by MEAG, OPC and SEPA. The reserve margin for the traditional operating companies, Southern Power and SEGCO at that time was 17.1%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands.

Jointly-Owned Facilities

Alabama Power, Georgia Power and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

	Total Capacity	Percentage Ownership Alabama Power	AEC	Georgia Power	OPC	MEAG	DALTON	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
	(Megawatts)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	–%	–%	–%	–%	–%	–%	–%	–%	–%
Plant Hatch	1,796	–	–	50.1	30.0	17.7	2.2	–	–	–	–	–
Plant Vogtle	2,320	–	–	45.7	30.0	22.7	1.6	–	–	–	–	–
Plant Scherer Units 1 and 2	1,636	–	–	8.4	60.0	30.2	1.4	–	–	–	–	–
Plant Wansley	1,779	–	–	53.5	30.0	15.1	1.4	–	–	–	–	–
Rocky Mountain	848	–	–	25.4	74.6	–	–	–	–	–	–	–
Intercession City, FL	143	–	–	33.3	–	–	–	66.7	–	–	–	–
Plant Stanton A	660	–	–	–	–	–	–	–	65%	28%	3.5%	3.5%

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A.

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

Titles to Property

The traditional operating companies', Southern Power's and SEGCO's interests in the principal plants (other than certain pollution control facilities, one small hydroelectric generating station leased by Georgia Power, combined cycle units at Plant Daniel leased by Mississippi Power and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control bonds of Alabama Power and Gulf Power and to excepted encumbrances as defined therein. At December 31, 2006, Gulf Power's interest in its principal plants was subject to a lien under a mortgage indenture. The mortgage indenture and the lien were discharged effective January 26, 2007. See Note 6 to the financial statements of Southern Company, Alabama Power and Gulf Power under "Assets Subject to Lien" and Note 7 to the financial statements of Mississippi Power under "Operating Leases – Plant Daniel Combined Cycle Generating Units" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Item 3. LEGAL PROCEEDINGS

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

United States of America v. Georgia Power and Savannah Electric
(United States District Court for the Northern District of Georgia)

See "Environmental Matters – New Source Review Actions" in Note 3 to Southern Company's and each traditional operating company's financial statements in Item 8 herein for information.

(2) **Environmental Remediation**

See "Environmental Matters – Environmental Remediation" in Note 3 to the financial statements of Southern Company, Georgia Power and Mississippi Power and "Retail Regulatory Matters – Environmental Remediation" in Note 3 to the financial statements of Gulf Power in Item 8 herein for information related to environmental remediation.

(3) **In re: Mirant Corporation, et al.**
(United States Bankruptcy Court for the Northern District of Texas)

See "Mirant Matters – Mirant Bankruptcy" in Note 3 to Southern Company's financial statements in Item 8 herein for information.

(4) MC Asset Recovery, LLC v. Southern Company (United States District Court for the Northern District of Georgia) (formerly styled *In re: Mirant Corporation, et al.* in the United States Bankruptcy Court for the Northern District of Texas)

See "Mirant Matters – MC Asset Recovery Litigation" in Note 3 to Southern Company's financial statements in Item 8 herein for information.

(5) In re: Mirant Corporation Securities Litigation (United States District Court for the Northern District of Georgia)

See "Mirant Matters – Mirant Securities Litigation" in Note 3 to Southern Company's financial statements in Item 8 herein for information.

(6) In re: Mirant Corporation ERISA Litigation (United States District Court for the Northern District of Georgia)

See "Mirant Matters – Southern Company Employee Savings Plan Litigation" in Note 3 to Southern Company's financial statements in Item 8 herein for information.

(7) Sierra Club, et al. v. Georgia Power (United States District Court for the Northern District of Georgia)

See "Plant Wansley Environmental Litigation" in Note 3 to Southern Company's and Georgia Power's financial statements in Item 8 herein for information.

(8) Right of Way Litigation

See "Right of Way Litigation" in Note 3 to Southern Company's, Georgia Power's, Gulf Power's and Mississippi Power's financial statements in Item 8 herein for information.

See Note 3 to each registrant's financial statements in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

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

Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power

None.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2006.

David M. Ratcliffe
Chairman, President, Chief Executive Officer and Director
Age 58
Elected in 1999. President since April 2004; Chairman and Chief Executive Officer since July 2004. Previously served as Chief Executive Officer of Georgia Power from June 1999 to April 2004; and President of Georgia Power from June 1999 to December 2003.

Andrew J. Dearman, III
Executive Vice President
Age 53
Elected in 2005. Executive Vice President since December 2005. Previously served as Senior Vice President from December 2000 until December 2005.

Dwight H. Evans
Executive Vice President
Age 58
Elected in 2001. Executive Vice President since May 2001.

Thomas A. Fanning
Executive Vice President, Chief Financial Officer and Treasurer
Age 49
Elected in 2003. Executive Vice President, Chief Financial Officer and Treasurer since April 2003. Previously served as President, Chief Executive Officer and Director of Gulf Power from 2002 to April 2003; and Executive Vice President, Treasurer and Chief Financial Officer of Georgia Power from 1999 to 2002.

Michael D. Garrett
Executive Vice President
Age 57
Elected in 2004. Executive Vice President since January 1, 2004. He also serves as President and Director of Georgia Power since January 1, 2004 and Chief Executive Officer of Georgia Power since April 2004. Previously served as President, Chief Executive Officer and Director of Mississippi Power from 2001 to 2003.

G. Edison Holland, Jr.
Executive Vice President, General Counsel and Secretary
Age 54
Elected in 2001. Executive Vice President and General Counsel since 2001.

Anthony R. James
Executive Vice President
Age 56
Elected in 2005. Executive Vice President of Southern Company since December 2005. Previously served as Chairman of Savannah Electric from December 2005 through January 2006 and President and Chief Executive Officer of Savannah Electric from April 2001 to December 2005.

Charles D. McCrary
Executive Vice President
Age 55
Elected in 1998. Executive Vice President of Southern Company since February 2002; President and Chief Executive Officer of Alabama Power since October 2001.

W. Paul Bowers
Executive Vice President of SCS
Age 50
Elected in 2001. Executive Vice President of SCS since May 2001 and previously served as President and Chief Executive Officer of Southern Power from May 2001 to March 2005.

J. Barnie Beasley
President and Chief Executive Officer of Southern Nuclear
Age 55
Elected in 2004. President and Chief Executive Officer of Southern Nuclear since September 2004. Previously served as Executive Vice President of Southern Nuclear from January 2004 to September 2004; and Vice President from July 1998 through December 2003.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 24, 2006) for one year until the first board meeting after the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2006.

Charles D. McCrary
President, Chief Executive Officer and Director
Age 55
Elected in 2001. President, Chief Executive Officer and Director since October 2001; Executive Vice President of Southern Company since February 2002.

Art P. Beattie
Executive Vice President, Chief Financial Officer and Treasurer
Age 52
Elected in 2004. Executive Vice President, Chief Financial Officer and Treasurer since February 2005. Previously served as Vice President and Comptroller of Alabama Power from 1998 through January 2005.

C. Alan Martin
Executive Vice President
Age 58
Elected in 1999. Executive Vice President of the Customer Service Organization since 2001.

Steven R. Spencer
Executive Vice President
Age 51
Elected in 2001. Executive Vice President of External Affairs since 2001.

Jerry L. Stewart
Senior Vice President
Age 57
Elected in 1999. Senior Vice President of Fossil and Hydro Generation since 1999.

The officers of Alabama Power were elected for a term running from the last annual organizational meeting of the directors (April 28, 2006) for one year until the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2006.

Michael D. Garrett
President, Chief Executive Officer and Director
Age 57
Elected in 2003. President and Chief Executive Officer of Georgia Power since April 2004. Previously served as President of Georgia Power from January 2004 to April 2004; President and Chief Executive Officer and Director of Mississippi Power from May 2001 to December 2003.

Mickey A. Brown
Executive Vice President
Age 59
Elected in 2001. Executive Vice President of the Customer Service Organization since January 2005. Previously served as Senior Vice President of Distribution from May 2001 to December 2005.

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer and Treasurer
Age 56
Elected in 2005. Executive Vice President, Chief Financial Officer and Treasurer since March 2005. Previously served as Senior Vice President, Comptroller and Chief Financial Officer of Southern Power from November 2002 to March 2005 and Vice President of SCS from June 2002 to March 2005; and Vice President, Comptroller and Chief Accounting Officer of Georgia Power from September 1995 to June 2002.

Christopher C. Womack
Executive Vice President
Age 48
Elected in 2001. Executive Vice President of External Affairs since March 2006. Previously served as Senior Vice President of Fossil and Hydro Generation and Senior Production Officer from December 2001 to February 2006.

Judy M. Anderson
Senior Vice President
Age 58
Elected in 2001. Senior Vice President of Charitable Giving since 2001.

Douglas E. Jones
Senior Vice President
Age 48
Elected in 2005. Senior Vice President of Fossil and Hydro Generation since March 2006. Previously served as Senior Vice President of Customer Service and Sales from January 2005 to February 2006; Executive Vice President of Southern Power from January 2004 to January 2005; Senior Vice President of SCS from December 2001 to January 2004.

James H. Miller, III
Senior Vice President and General Counsel
Age 57
Elected in 2004. Senior Vice President and General Counsel since March 2004. Previously served as Vice President and Associate General Counsel for SCS and Senior Vice President, General Counsel and Assistant Secretary of Southern Power from 2001 to 2004.

Each of the above is currently an executive officer of Georgia Power, serving a term running from the last annual organizational meeting of the directors (May 17, 2006) for one year until the next annual meeting or until their successors are elected and qualified.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2006.

Anthony J. Topazi
President, Chief Executive Officer and Director
Age 56
Elected in 2003. President, Chief Executive Officer and Director since January 1, 2004. Previously served as Executive Vice President of Southern Company Generation and Energy Marketing from November 2000 to December 2003; Senior Vice President of Southern Power from November 2002 to December 2003; and Vice President of Southern Power from 2001 until November 2002.

John W. Atherton
Vice President
Age 46
Elected in 2004. Vice President of External Affairs since January 2005. Previously served as the Director of Economic Development from September 2003 to January 2005; Manager, Sales and Marketing Services from April 2002 to August 2003; and Manager, State Legislative Affairs from August 1996 to April 2002.

Kimberly D. Flowers
Vice President
Age 42
Elected in 2005. Vice President and Senior Production Officer since March 2005. Previously served as Plant Manager, Plant Bowen, Georgia Power from November 2000 until March 2005.

Donald R. Horsley
Vice President
Age 52
Elected in 2006. Vice President of Customer Services and Retail Marketing since April 2006. Previously served as Vice President of Transmission at Alabama Power from March 2005 to March 2006 and Manager, Transmission Lines at Alabama Power from February 2001 to March 2005.

Frances V. Turnage
Vice President, Treasurer and
Chief Financial Officer
Age 58
Elected in 2005. Vice President, Treasurer and Chief Financial Officer since March 2005. Previously served as Comptroller from 1993 to March 2005.

The officers of Mississippi Power were elected for a term running from the last annual organizational meeting of the directors (April 12, 2006) for one year until the next annual meeting or until their successors are elected and have qualified.

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PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices for each quarter of the past two years were as follows:

	High	Low
2006		
First Quarter	$35.89	$32.34
Second Quarter	33.25	30.48
Third Quarter	35.00	32.01
Fourth Quarter	37.40	34.49
2005		
First Quarter	$34.34	$31.14
Second Quarter	35.00	31.60
Third Quarter	36.47	33.24
Fourth Quarter	36.33	32.76

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(2) Number of Southern Company's common stockholders of record at December 31, 2006:
110,259

Each of the other registrants have one common stockholder, Southern Company.

(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2006	2005
		(in thousands)	
Southern Company	First	$276,442	$265,958
	Second	287,704	277,679
	Third	287,845	277,625
	Fourth	288,440	276,306
Alabama Power	First	110,150	102,475
	Second	110,150	102,475
	Third	110,150	102,475
	Fourth	110,150	102,475
Georgia Power	First	157,500	145,700
	Second	157,500	145,700
	Third	157,500	145,700
	Fourth	157,500	145,700
Gulf Power	First	17,575	17,100
	Second	17,575	17,100
	Third	17,575	17,100
	Fourth	17,575	17,100
Mississippi Power	First	16,300	15,500
	Second	16,300	15,500
	Third	16,300	15,500
	Fourth	16,300	15,500

In 2005 and 2006, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2006	2005
		(in millions)	
Southern Power	First	$ -	$ -
	Second	38.9	-
	Third	19.4	36.2
	Fourth	19.4	36.2

The dividend paid per share of Southern Company's common stock was 35.75¢ for first quarter of 2005 and 37.25¢ for the remaining quarters of 2005 and the first quarter of 2006. For the second, third and fourth quarters of

2006, the dividend paid per share of Southern Company's common stock was 38.75¢.

Southern Power's credit facility contains potential limitations on the payment of common stock dividends. At December 31, 2006, Southern Power was in compliance with the conditions of this credit facility and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restriction" in Item 8 herein for additional information regarding these restrictions.

(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at pages II-80 and II-81.

Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-136 and II-137.

Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-192 and II-193.

Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-242 and II-243.

Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-294 and II-295.

Southern Power. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at page II-326.

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

Southern Company. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-10 through II-37.

Alabama Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-84 through II-103.

Georgia Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-140 through II-159.

Gulf Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-196 through II-214.

Mississippi Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-246 through II-265.

Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-298 through II-311.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS - FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 6 to the financial statements of Southern Company, each traditional operating company and Southern Power under "Financial Instruments" in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2006 FINANCIAL STATEMENTS

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

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Southern Company, the traditional operating companies and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective in alerting them in a timely manner to material information relating to their company (including its consolidated subsidiaries, if any) required to be included in periodic filings with the SEC.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

(1) Southern Company

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-7 of this Form 10-K.

(2) Traditional operating companies and Southern Power

Not applicable because these companies are not accelerated filers.

(b) Attestation Report of the Registered Public Accounting Firm.

(1) Southern Company

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding management's assessment of Southern Company's internal control over financial reporting and the effectiveness of Southern Company's internal control over financial reporting is included on page II-8 of this Form 10-K.

(2) Traditional operating companies and Southern Power

Not applicable because these companies are not accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2006 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

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THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

Southern Company's management is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2006.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on management's assessment of the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2006. Deloitte & Touche LLP's report, which expresses unqualified opinions on management's assessment and on the effectiveness of Southern Company's internal control over financial reporting, is included herein.

David M. Ratcliffe
Chairman, President, and Chief Executive Officer

Thomas A. Fanning
Executive Vice President, Chief Financial Officer, and Treasurer

February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Southern Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-7), that Southern Company (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 26, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding a change in the method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte + Touche LLP

Atlanta, Georgia
February 26, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company and Subsidiary Companies (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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, such consolidated financial statements (pages II-38 to II-79) present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 the Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

The primary business of Southern Company (the Company) is electricity sales in the Southeast by the traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – and Southern Power. Savannah Electric and Power Company (Savannah Electric) was also a traditional operating company subsidiary of Southern Company until being merged with and into Georgia Power effective July 1, 2006. Southern Power constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of Southern Company's electricity business. These factors include the traditional operating companies' ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and storm restoration following multiple hurricanes. Since the beginning of 2004, each of the traditional operating companies completed successful retail base rate proceedings. These regulatory actions have provided earnings stability and enabled the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and to continue environmental improvements at the generating plants. During 2005 and 2006, each of the traditional operating companies completed proceedings as necessary to address fuel and storm damage cost recovery. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business and federal regulatory policy, which may impact Southern Company's level of participation in this market. Southern Power continued executing its regional strategy in 2006 through the acquisition of power plants in North Carolina and Florida. Consistent with prior acquisitions, the newly acquired plants have associated power purchase agreements (PPAs) in place. The Company continues to face regulatory challenges related to transmission and market power issues at the national level.

Southern Company's other business activities include an investment in a synthetic fuel producing entity (which claims federal income tax credits designed to offset its operating losses), leveraged lease projects, telecommunications, and energy-related services. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly. The synthetic fuel tax credits will no longer be available after December 31, 2007. In January 2006, the sale of the Company's natural gas marketing business was completed.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than four million customers, Southern Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share (EPS), excluding earnings from synthetic fuel investments. Southern Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2006 Peak Season EFOR of 1.11 percent is better than the target and a significant improvement over 2005 Peak Season EFOR. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2006 exceeded most targets on these reliability measures.

Southern Company's synthetic fuel investments generate tax credits as a result of synthetic fuel production. Due to higher oil prices in 2006, these tax credits were partially phased out and one synfuel investment was terminated. As a result, Southern Company's synthetic fuel investments did not contribute significantly to earnings and EPS during 2006. These tax credits will no longer be available after December 31, 2007. Southern Company management uses EPS, excluding synfuel earnings, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of earnings and EPS excluding the results of the synthetic fuel investments also is useful for investors because it provides investors with additional information for purposes of comparing Southern Company's performance for such periods. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with generally accepted accounting principles.

Southern Company's 2006 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2006 Target Performance	2006 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR	2.75% or less	1.11%
Basic EPS	$2.15 – $2.20	$2.12
EPS, excluding synfuel earnings	$2.03 – $2.08	$2.10

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income was $1.57 billion in 2006, a decrease of 1.1 percent from the prior year. The lower earnings compared with the prior year were primarily the result of a reduction of tax credits related to the production of synthetic fuels. This decrease was largely offset by continued economic strength and a growing customer base. Net income was $1.59 billion in 2005 and $1.53 billion in 2004, reflecting increases over the prior year of 3.8 percent and 4.0 percent, respectively. Basic EPS, including discontinued operations, was $2.12 in 2006, $2.14 in 2005, and $2.07 in 2004. Diluted EPS, which factors in additional shares related to stock options, was 2 cents lower than basic EPS for 2006 and 1 cent lower for each of 2005 and 2004.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.535 in 2006, $1.475 in 2005, and $1.415 in 2004. In January 2007, Southern Company declared a quarterly dividend of 38.75 cents per share. This is the 237th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 70 to 75 percent of net income, excluding earnings from synthetic fuel businesses. For 2006, the actual payout ratio was 73 percent, excluding synthetic fuel earnings, and 72.5 percent overall.

RESULTS OF OPERATIONS

Electricity Businesses

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast. A condensed income statement for the electricity business is as follows:

	Amount	Increase (Decrease) from Prior Year		
	2006	**2006**	2005	2004
	(in millions)			
Electric operating revenues	**$14,088**	**$ 810**	$1,813	$718
Fuel	**5,143**	**655**	1,089	400
Purchased power	**543**	**(188)**	88	170
Other operations and maintenance	**3,290**	**70**	215	148
Depreciation and amortization	**1,164**	**27**	229	(64)
Taxes other than income taxes	**715**	**39**	52	40
Total electric operating expenses	**10,855**	**603**	1,673	694
Operating income	**3,233**	**207**	140	24
Other income, net	**53**	**(9)**	38	22
Interest expenses	**751**	**75**	62	19
Income taxes	**949**	**50**	24	30
Net income	**$ 1,586**	**$ 73**	$ 92	$ (3)

Revenues

Details of electric operating revenues are as follows:

	2006	2005	2004
	(in millions)		
Retail – prior year	**$11,165**	$ 9,732	$ 8,875
Change in –			
Base rates	**72**	236	41
Sales growth	**40**	184	216
Weather	**35**	34	48
Fuel and other cost recovery clauses	**489**	979	552
Retail – current year	**11,801**	11,165	9,732
Sales for resale	**1,822**	1,667	1,341
Other electric operating revenues	**465**	446	392
Electric operating revenues	**$14,088**	$13,278	$11,465
Percent change	**6.1%**	15.8%	6.7%

Retail revenues increased $636 million, $1.4 billion, and $857 million in 2006, 2005, and 2004, respectively. The significant factors driving these changes are shown in the preceding table. The increase in base rates in 2005 is primarily due to approval by the Georgia Public Service Commission (PSC) of a retail base rate increase at Georgia Power. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. Certain of the traditional operating companies also have clauses to recover other costs, such as environmental, storm damage, new plants, and PPAs.

Sales for resale revenues consist of PPAs with investor-owned utilities and electric cooperatives, short-term opportunity sales, and unit power sales contracts. Southern Company's average wholesale contract extends more than 10 years and, as a result, the Company has significantly limited its remarketing risk. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. Revenues associated with PPAs and opportunity sales were as follows:

	2006	2005	2004
	(in millions)		
Other power sales –			
Capacity and other	**$ 499**	$ 430	$308
Energy	**841**	799	635
Total	**$1,340**	$1,229	$943

Capacity revenues under unit power sales contracts, principally sales to Florida utilities, reflect the recovery of fixed costs and a return on investment, and energy is generally sold at variable cost. Unit power kilowatt-hour (KWH) sales increased 0.2 percent, 1.7 percent, and 1.9 percent in 2006, 2005, and 2004, respectively. Fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales customers, influence changes in these sales. However, because the energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2006	2005	2004
	(in millions)		
Unit power –			
Capacity	**$208**	$201	$185
Energy	**274**	237	213
Total	**$482**	$438	$398

In 2006, sales for resale revenues increased $155 million as a result of a 10.5 percent increase in the average cost of fuel per net KWH generated, as well as revenues resulting from new PPAs in 2006. In addition, Southern Company assumed four PPAs through the acquisitions of Plants DeSoto and Rowan in June and September 2006, respectively. The 2006 increase was partially offset by a decrease in opportunity sales.

In 2005, sales for resale revenues increased $326 million primarily due to a 26.5 percent increase in the average cost of fuel per net KWH generated. In addition, Southern Company entered into new PPAs with 30 electric membership cooperatives (EMCs) and Flint EMC, both beginning in January 2005, and assumed two PPAs in June 2005 in connection with the acquisition of Plant Oleander.

In 2004, sales for resale revenues decreased $17 million primarily due to a lower price differential between market prices and the Company's marginal cost that reduced the availability of short-term opportunity sales. Milder summer weather throughout the Southeast also reduced demand.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. KWH sales for 2006 and the percent change by year were as follows:

	KWH	Percent Change		
	2006	2006	2005	2004
	(in billions)			
Residential	52.4	2.5%	2.8%	3.9%
Commercial	53.0	2.2	3.6	3.4
Industrial	55.0	(0.2)	(2.2)	3.6
Other	0.9	(7.6)	(0.9)	0.8
Total retail	161.3	1.4	1.2	3.6
Sales for resale	40.1	6.1	7.3	(13.0)
Total	201.4	2.3	2.3	0.1

Retail energy sales in 2006 increased 2.3 billion KWH as a result of customer growth of 1.7 percent, sustained economic growth primarily in the residential and commercial customer classes, and warmer weather in 2006 when compared to 2005. Retail energy sales in 2005 increased 1.9 billion KWH as a result of sustained economic growth and customer growth of 1.2 percent. Hurricane Katrina dampened customer growth from previous years and was the primary contributor to the decrease in industrial sales in 2005. In addition, in 2005, some Georgia Power industrial customers were reclassified from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC resulting in higher commercial sales and lower industrial sales in 2005 when compared with 2004. Retail energy sales in 2004 were strong across all customer classes as a result of an improved economy in the Southeast and customer growth of 1.5 percent.

Energy sales for resale increased by 2.3 billion KWH in 2006, increased by 2.6 billion KWH in 2005, and decreased by 5.3 billion KWH in 2004. The increases in sales for resale in 2006 and 2005 are related primarily to the new PPAs discussed above. The decrease in 2004 compared with 2003 is primarily due to a lower price differential between market prices and the Company's marginal cost that reduced the availability of short-term opportunity sales. Milder summer weather throughout the Southeast also reduced demand.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the electric utilities. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Details of Southern Company's generation, fuel, and purchased power are as follows:

	2006	2005	2004
Total generation (billions of KWH)	201	195	188
Total purchased power (billions of KWH)	10	11	15
Sources of generation (percent) –			
Coal	70%	71%	69%
Nuclear	15	15	16
Gas	13	11	12
Hydro	2	3	3
Cost of fuel, generated (cents per net KWH) –			
Coal	2.40	1.93	1.75
Nuclear	0.47	0.47	0.46
Gas	6.63	8.52	4.90
Average cost of fuel, generated (cents per net KWH)	2.64	2.39	1.89
Average cost of purchased power (cents per net KWH)	5.64	7.14	4.48

Fuel and purchased power expenses were $5.7 billion in 2006, an increase of $467 million or 8.9 percent above the prior year costs. This increase was the result of a $319 million increase in the cost of fuel and purchased power and $148 million related to an increase in total KWH generated and purchased.

In 2005, fuel and purchased power expenses were $5.2 billion, an increase of $1.2 billion or 29.1 percent above 2004 costs. This increase was the result of a $1.2 billion increase in the cost of fuel and purchased power, partially offset by $47 million related to a decrease in total KWH generated and purchased.

Fuel and purchased power expenses were $4.0 billion in 2004, an increase of $570 million or 16.4 percent above 2003 costs. This increase was the result of a $473 million increase in the cost of fuel and purchased power and $97 million related to an increase in total KWH generated and purchased.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the traditional operating companies' fuel cost recovery provisions. Likewise, Southern Power's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.3 billion, $3.2 billion, and $3.0 billion, increasing $70 million, $215 million, and $148 million in 2006, 2005, and 2004, respectively. Other production expenses at fossil, hydro, and nuclear plants increased $3 million, $58 million, and $53 million in 2006, 2005, and 2004, respectively. Production expenses fluctuate from year to year due to variations in outage schedules, flexible spending projects, and normal increases in costs.

Administrative and general expenses increased $29 million in 2006 as a result of a $17 million increase in salaries and wages and a $24 million increase in pension expense, partially offset by a $16 million reduction in medical expenses. Administrative and general expenses increased $73 million in 2005 related to a $33 million increase in employee benefits; a $22 million increase in shared service expenses, primarily increases in Sarbanes-Oxley Act compliance costs, legal costs, and other corporate expenses; and a $9 million increase in property damage. Administrative and general expenses increased $106 million in 2004 primarily related to a $41 million increase in employee benefits, a $23 million increase in shared service expenses, primarily nuclear security, and a $13 million increase in property insurance.

Transmission and distribution expenses increased $30 million, $60 million, and $49 million in 2006, 2005, and 2004, respectively. Transmission and distribution expenses increased in 2006 primarily due to expenses associated with recovery of prior year storm costs through natural disaster recovery clauses and additional investment in distribution to meet customer growth. Transmission and distribution expenses increased in 2005 primarily as a result of $48 million of expenses recorded by Alabama Power in accordance with an accounting order approved by the Alabama PSC primarily to offset the costs of Hurricane Ivan and restore the natural disaster reserve. In accordance with the accounting order, Alabama Power also returned certain regulatory liabilities related to deferred income taxes to its retail customers; therefore, the combined effect of the accounting order had no impact on net income. See Note 3 to the financial statements under "Storm Damage Cost Recovery" for additional information. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules, flexible spending projects, and normal increases in costs and are the primary basis for the 2004 increase.

The 2004 increase in other operations and maintenance expenses was partially offset by a $60 million regulatory liability related to Plant Daniel that was expensed in 2003.

Depreciation and Amortization Expenses

Depreciation and amortization expenses increased $27 million in 2006 as a result of the acquisitions of Plants DeSoto, Rowan, and Oleander in June 2006, September 2006, and June 2005, respectively, and a reduction in the amortization of the Plant Daniel regulatory liability. An increase in depreciation rates at Southern Power associated with adoption of a new depreciation study also contributed to the 2006 increase. Partially offsetting the 2006 increase was the amortization of a Georgia Power regulatory liability related to the levelization of certain purchased power capacity costs as ordered by the Georgia PSC under the terms of the retail rate order effective January 1, 2005. See Note 3 to the financial statements under "Georgia Power Retail Regulatory Matters" for additional information.

Depreciation and amortization expenses increased $229 million in 2005 as a result of additional plant in service and from the expiration in 2004 of certain provisions in Georgia Power's retail rate plan for the three years ended December 31, 2004 (2001 Retail Rate Plan). In accordance with the 2001 Retail Rate Plan, Georgia Power amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power capacity costs in rates evenly over the three years ended December 31, 2004. See Note 3 to the financial statements under "Georgia Power Retail Regulatory Matters" for additional information.

Depreciation and amortization expenses declined by $64 million in 2004 primarily as a result of amortization of the Plant Daniel regulatory liability and a Georgia Power regulatory liability related to the levelization of certain purchased power capacity costs that reduced amortization expense by $17 million and $90 million, respectively, from the prior year. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Mississippi Power" herein and Note 3 to the financial statements under "Georgia Power Retail Regulatory Matters" for more information on these regulatory adjustments. These reductions were partially offset by a higher depreciable plant base.

Taxes Other Than Income Taxes

Taxes other than income taxes increased by $39 million in 2006 primarily as a result of increases in franchise and municipal gross receipts taxes associated with increases in revenues from energy sales as well as increases in property taxes associated with additional plant in service. Taxes other than income taxes increased by $52 million in 2005 primarily as a result of increases in franchise and municipal gross receipts taxes associated with increases in revenues from energy sales. In 2004, taxes other than income taxes increased by $40 million primarily as a result of additional plant in service and a higher property tax base.

Interest Expenses

Total interest charges and other financing costs increased by $75 million in 2006 due to a $78 million increase associated with $708 million in additional debt outstanding at December 31, 2006 compared to December 31, 2005 and a $7 million increase associated with an increase in average interest rates on variable rate debt, partially offset by a $6 million increase in capitalized interest associated with construction projects and a $3 million reduction in other interest costs. Total interest charges and other financing costs increased by $62 million in 2005 associated with an additional $863 million in debt outstanding at December 31, 2005 as compared to December 31, 2004 and an increase in average interest rates on variable rate debt. Variable rates on pollution control bonds are highly correlated with the Bond Market Association (BMA) Municipal Swap Index, which averaged 2.5 percent in 2005 and 1.2 percent in 2004. Variable rates on commercial paper and senior notes are highly correlated with the one-month London Interbank Offer Rate (LIBOR), which averaged 3.4 percent in 2005 and 1.5 percent in 2004. An additional $17 million increase in 2005 was the result of a lower percentage of interest costs capitalized as construction projects reached completion. The $19 million increase in interest charges and other financing costs in 2004 was also the result of a lower percentage of interest costs capitalized as construction projects reached completion.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in synthetic fuels and leveraged lease projects, telecommunications, and energy-related services. These businesses are classified in general categories and may comprise one or more of the following subsidiaries: Southern Company Holdings invests in various energy-related projects, including synthetic fuels and leveraged lease projects that receive tax benefits, which contribute significantly to the economic results of these investments; SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast; Southern Telecom provides fiber optics services in the Southeast; and Southern Company Gas was a retail gas marketer serving customers in the State of Georgia. On January 4, 2006, Southern Company Gas completed the sale of substantially all of its assets and is reflected in the condensed income statement below as discontinued operations. See Note 3 to the financial statements under "Southern Company Gas Sale" for additional information. A condensed income statement for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year		
	2006	**2006**	2005	2004
	(in millions)			
Operating revenues	**$ 268**	**$ (8)**	$ 12	$ (7)
Other operations and maintenance	**238**	**(59)**	12	28
Depreciation and amortization	**36**	**(3)**	(2)	(9)
Taxes other than income taxes	**3**	**(1)**	1	1
Total operating expenses	**277**	**(63)**	11	20
Operating income/(loss)	**(9)**	**55**	1	(27)
Equity in losses of unconsolidated subsidiaries	**(60)**	**62**	(25)	3
Leveraged lease income	**69**	**(5)**	4	4
Other income, net	**(31)**	**(18)**	(6)	(15)
Interest expenses	**149**	**48**	18	(21)
Income taxes	**(168)**	**136**	(14)	(63)
Discontinued operations, net of tax	**(1)**	**(1)**	(3)	12
Net income/(loss)	**$ (13)**	**$ (91)**	$(33)	$ 61

Southern Company's non-electric operating revenues decreased $8 million in 2006 primarily as a result of a $21 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and lower equipment and accessory sales. The 2006 decrease was partially offset by a $12 million increase in fuel procurement service revenues. Higher production and increased fees in the synthetic fuel business contributed to the $12 million increase in 2005. The $7 million decrease in 2004 was primarily due to lower operating revenues in one of the Company's energy-related services businesses, partially offset by an increase in SouthernLINC Wireless revenues as a result of increased wireless subscribers.

Other operations and maintenance expenses for these other businesses declined $59 million in 2006 primarily as a result of $32 million of lower production expenses related to the termination of Southern Company's membership interest in one of the synthetic fuel entities, $13 million attributed to the wind-down of one of the Company's energy-related services businesses, and $7 million of lower expenses resulting from the March 2006 sale of a subsidiary that provided rail car maintenance services. Other operations and maintenance expenses increased by $12 million in 2005 as a result of $9 million of higher losses for property damage, $2 million in higher network costs at SouthernLINC Wireless, and an $11 million increase in shared service expenses, partially offset by the $12.5 million bad debt reserve in 2004 discussed below. Other operations and maintenance expenses increased $28 million in 2004 primarily due to a $3 million increase in advertising, a $5 million increase in shared services expenses, and a $12.5 million bad debt reserve related to additional federal income taxes and interest Southern Company paid on behalf of Mirant Corporation (Mirant). See FUTURE EARNINGS POTENTIAL – "Mirant Matters" herein and Note 3 to the financial statements under "Mirant Matters – Mirant Bankruptcy" for additional information.

The 2006 and 2005 decreases in depreciation and amortization expenses when compared to the prior years were not material. Depreciation and amortization expenses decreased $9 million in 2004 primarily as a result of $10 million of expenses associated with the repurchase of debt at Southern Company Holdings in 2003.

Southern Company made investments in two synthetic fuel production facilities that generate operating losses. These investments also allow Southern Company to claim federal income tax credits that offset these operating losses and make the projects profitable. The decrease in equity in losses of unconsolidated subsidiaries in 2006 reflects the result of terminating Southern Company's membership interest in one of the synthetic fuel entities which reduced the amount of Southern Company's share of the losses and, therefore, the funding obligation for the year. The decrease also resulted from lower operating expenses while the production facilities at the other synthetic fuel entity were idled from May to September 2006 due to higher oil prices. The increase in equity in losses of unconsolidated subsidiaries in 2005 reflects the results of additional production expenses at the synthetic fuel production facilities. The 2004 decrease in equity in losses of unconsolidated subsidiaries when compared to the prior year was not material. The federal income tax credits resulting from these investments totaled $65 million in 2006, $177 million in 2005, and $146 million in 2004. In 2004, a $37 million reserve related to these tax credits was reversed following the settlement of an Internal Revenue Service (IRS) audit. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Synthetic Fuel Tax Credits" herein for further information.

The $18 million decrease in other income in 2006 as compared with 2005 resulted from a $25 million decrease related to changes in the value of derivative transactions in the synthetic fuel business and a $16 million decrease related to the impairment of investments in the synthetic fuel entities, partially offset by the release of $6 million in certain contractual obligations associated with these investments. The 2005 decrease in other income when compared to the prior year was not material. The decrease in other income in 2004 as compared with 2003 reflects a $15 million gain for a Southern Telecom contract settlement during 2003.

Total interest charges and other financing costs increased by $48 million in 2006 due to a $19 million increase associated with $149 million in additional debt outstanding at December 31, 2006 as compared to December 31, 2005, a $12 million increase associated with an increase in average interest rates on variable rate debt, a $6 million loss on the early redemption of long-term debt payable to affiliated trusts in January 2006, and a $16 million loss on the repayment of long-term debt payable to affiliated trusts in December 2006. The 2006 increase is partially offset by a $4 million reduction in other interest costs. Interest expense increased by $18 million in 2005 associated with an additional $283 million in debt outstanding and a 164 basis point increase in average interest rates on variable rate debt. Interest expense decreased $21 million in 2004 as a result of the parent company's redemption of preferred securities in 2003. This decrease was partially offset by an increase in outstanding long-term debt in 2004.

The $136 million increase in income taxes in 2006 as compared with 2005 resulted from an $80 million decrease in synthetic fuel tax credits as a result of terminating the Company's membership interest in one of the synthetic fuel entities and curtailing production at the other synthetic fuel entity from May to September 2006. In addition, $32 million of tax credit reserves were recorded in 2006 due to an anticipated phase-out of synthetic fuel tax credits due to higher oil prices. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Synthetic Fuel Tax Credits" herein for further information. The 2005 decrease in income taxes when compared to the prior year was not material. The $63 million decrease in income taxes in 2004 as compared with 2003 resulted from a $19 million increase in synthetic fuel tax credits as a result of increased production and a $44 million change in a reserve recorded related to these tax credits.

Effects of Inflation

The traditional operating companies and Southern Power are subject to rate regulation and party to long-term contracts that are generally based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on Southern Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss nor the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the traditional operating companies' approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the southeastern United States. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. The level of future earnings depends on numerous factors including the Federal Energy Regulatory Commission's (FERC) market-based rate investigation, creditworthiness of customers, total generating capacity available in the Southeast, and the successful remarketing of capacity as current contracts expire. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Another major factor is the profitability of the competitive market-based wholesale generating business and federal regulatory policy, which may impact Southern Company's level of participation in this market. Future earnings for the electricity business in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the service area.

Southern Company system generating capacity increased 1,276 megawatts in 2006. The acquisition by Southern Power of Plants DeSoto and Rowan added 1,330 megawatts to the fleet while generating capacity was reduced by 54 megawatts due to the retirement of two fossil units and the re-rating of one hydro unit. In general, Southern Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of Southern Company's regulated retail markets, both of which are optimized by limited energy trading activities.

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

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

Southern Company believes that the traditional operating companies complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in any one of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. These regulatory revisions have been adopted by each of the states within Southern Company's service territory. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the individual state implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against Georgia Power for alleged violations of the Clean Air Act at four of the units at Plant Wansley. The civil action requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for Georgia Power on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

Environmental Statutes and Regulations

General

Southern Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, Southern Company had invested approximately $3.1 billion in capital projects to comply with these requirements, with annual totals of $661 million, $423 million, and $300 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $1.66 billion, $1.65 billion, and $1.27 billion for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for Southern Company. Through 2006, the Company had spent approximately $2.5 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2, NO_x, and mercury emissions, maintain compliance with existing regulations, and meet new requirements.

Approximately $1.3 billion of the expenditures related to reducing NO_x emissions pursuant to state and federal requirements were in connection with the EPA's one-hour ozone air quality standard and the 1998 regional NO_x reduction rules. In addition, in 2006, Gulf Power completed implementation of the terms of a 2002 agreement with the State of Florida to help ensure attainment of the ozone standard in the Pensacola, Florida area. The conditions of the agreement, which required installing additional controls on certain units and retiring three older units at a plant near Pensacola, totaled approximately $133.8 million, and have been approved under Gulf Power's environmental cost recovery clause.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Areas within Southern Company's service area that were designated as nonattainment under the eight-hour ozone standard included Macon (Georgia), Jefferson and Shelby Counties, near and including Birmingham (Alabama), and a 20-county area within metropolitan Atlanta. Macon is in the process of seeking redesignation by the EPA as an attainment area and is preparing a maintenance plan for approval. The Birmingham area was redesignated to attainment with the eight-hour ozone standard by the EPA on June 12, 2006, and the EPA subsequently approved a maintenance plan for the area to address future exceedances of the standard. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, are currently required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within Southern Company's service area in Alabama and Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA is expected to publish its final rule for implementation of the existing fine particulate matter standard in early 2007. State plans for addressing the nonattainment designations under the existing standard are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. On September 21, 2006, the EPA published a final rule lowering the 24-hour fine particulate matter air quality standard even further and plans to designate nonattainment areas based on the new standard by December 2009. The final outcome of this matter cannot be determined at this time.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including each of the states within Southern Company's service area, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at Southern Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed, and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

Georgia Power is retrofitting a closed-loop recirculating cooling tower at one facility under the Clean Water Act to cool water prior to discharge and is considering undertaking similar work at an additional facility. The total estimated capital cost for this project is $96 million. Southern Company is also considering similar projects at other facilities.

Environmental Remediation

Southern Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release of hazardous substances. Under these various laws and regulations, the traditional operating companies could incur substantial costs to clean up properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. The Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, the Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

Each of the traditional operating companies and Southern Power has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $19.7 million for the Southern Company system. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the traditional operating companies and Southern Power may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $55.4 million for the Southern Company system, of which $15.5 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

Southern Company and its subsidiaries believe that there is no meritorious basis for these proceedings and are vigorously defending themselves in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on Southern Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require Southern Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Market-Based Rate Authority" and "Generation Interconnection Agreements" above for additional information. The final outcome of these proceedings cannot now be determined. However, Southern Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Alabama Power

In October 2005, the Alabama PSC approved a revision to the Rate Stabilization and Equalization Plan (Rate RSE) requested by Alabama Power. Effective January 2007, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4 percent per year and any annual adjustment is limited to 5 percent. Rates remain unchanged when the projected return on common equity (ROE) ranges between 13 percent and 14.5 percent. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range. Alabama Power made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007 is 4.76 percent, or $193 million annually and, became effective in January 2007. See Note 3 to the financial statements under "Alabama Power Retail Regulatory Matters" for further information.

Georgia Power

In December 2004, the Georgia PSC approved the three-year retail rate plan ending December 31, 2007 (2004 Retail Rate Plan) for Georgia Power. Under the terms of the 2004 Retail Rate Plan, Georgia Power's earnings are evaluated against a retail ROE range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent are applied to rate refunds, with the remaining one-third retained by Georgia Power. Retail rates and customer fees were increased by approximately $203 million in January 2005 to cover the higher costs of purchased power, operations and maintenance expenses, environmental compliance, and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability.

Georgia Power is required to file a general rate case on or about July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. See Note 3 to the financial statements under "Georgia Power Retail Regulatory Matters" for additional information.

Effective July 1, 2006, Savannah Electric was merged into Georgia Power. See "Fuel Cost Recovery" herein for additional information.

Mississippi Power

In February 2007, Mississippi Power filed with the Mississippi PSC its annual Environmental Compliance Overview (ECO) Plan evaluation for 2007. Mississippi Power requested an 86 cent per 1,000 KWH increase for retail customers. This increase represents approximately $7.5 million per year in annual revenues for Mississippi Power. Hearings with the Mississippi PSC are expected to be held in April 2007. The outcome of the 2007 filing cannot now be determined. In April 2006, the Mississippi PSC approved Mississippi Power's 2006 ECO Plan, which included a 12 cent per 1,000 KWH reduction for retail customers. This decrease represented a reduction of approximately $1.3 million per year in annual revenues for Mississippi Power. The new rates were effective in April 2006.

In December 2006, Mississippi Power submitted its annual Performance Evaluation Plan (PEP) filing for 2007, which resulted in no rate change. Pursuant to the rate schedule, an order is not required from the Mississippi PSC for Mississippi Power to continue to bill the filed rate in effect. In March 2006, the Mississippi PSC approved Mississippi Power's 2006 PEP filing, which included an annual retail base rate increase of 5 percent, or $32 million that was effective in April 2006. Ordinarily, PEP limits annual rate increases to 4 percent; however, Mississippi Power had requested that the Mississippi PSC approve a temporary change to allow it to exceed this cap as a result of the ongoing effects of Hurricane Katrina.

In May 2004, the Mississippi PSC approved Mississippi Power's request to reclassify to jurisdictional cost of service the 266 megawatts of Plant Daniel unit 3 and 4 capacity, effective January 1, 2004. The Mississippi PSC authorized Mississippi Power to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. Mississippi Power is amortizing the regulatory liability established pursuant to the Mississippi PSC's order to earnings as follows: $16.5 million in 2004, $25.1 million in 2005, $13.0 million in 2006, and $5.7 million in 2007, resulting in expense reductions in each of those years.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Over the past two years, the traditional operating companies have continued to experience higher than expected fuel costs for coal, natural gas, and uranium. These higher fuel costs have increased the under recovered fuel costs included in the balance sheets to $1.3 billion at December 31, 2006. The traditional operating companies continuously monitor the under recovered fuel cost balance in light of these higher fuel costs. Each of the traditional operating companies received approval in 2005 and/or 2006 to increase its fuel cost recovery factors to recover existing under recovered amounts as well as projected future costs.

Alabama Power fuel costs are recovered under Rate ECR (Energy Cost Recovery), which provides for the addition of a fuel and energy cost factor to base rates. In December 2005, the Alabama PSC approved an increase that allows for the recovery of approximately $227 million in existing under recovered fuel costs over a two-year period. As of December 31, 2006, Alabama Power had an under recovered fuel balance of approximately $301 million.

In March 2006, Georgia Power and Savannah Electric filed a combined request for fuel cost recovery rate changes with the Georgia PSC to be effective July 1, 2006, the effective date of the merger of Savannah Electric into Georgia Power. On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in Georgia Power's total annual fuel billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required Georgia Power to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, Georgia Power filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate.

On November 13, 2006, under an agreement with the Georgia PSC staff, Georgia Power filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs. On February 6, 2007, the Georgia PSC ruled on the request and approved an increase in Georgia Power's total annual billings of approximately $383 million. The Georgia PSC order reduced Georgia Power's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires Georgia Power to file for a new fuel cost recovery rate no later than March 1, 2008. The new rates will become effective on March 1, 2007. Estimated under recovered fuel costs are to be recovered through May 2009 for customers in the former Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, Georgia Power had an under recovered fuel balance of approximately $898 million.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Based on their respective state PSC orders, a portion of the under recovered regulatory clause revenues for Alabama Power and Georgia Power was reclassified from current assets to deferred charges and other assets in the balance sheet. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Alabama Power Retail Regulatory Matters" and "Georgia Power Retail Regulatory Matters" for additional information.

Storm Damage Cost Recovery

In July 2005 and August 2005, Hurricanes Dennis and Katrina, respectively, hit the Gulf Coast of the United States and caused significant damage within Southern Company's service area, including portions of the service areas of Gulf Power, Alabama Power, and Mississippi Power. In addition, Hurricane Ivan hit the Gulf Coast of Florida and Alabama in September 2004, causing significant damage to the service areas of both Gulf Power and Alabama Power. Each retail operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property. In addition, each of the affected traditional operating companies has been authorized by its state PSC to defer the portion of the hurricane restoration costs that exceeded the balance in its storm damage reserve account. As of December 31, 2006, the under recovered balance in Southern Company's storm damage reserve accounts totaled approximately $89 million, of which approximately $57 million and $32 million, respectively, are included in the balance sheets herein under "Other Current Assets" and "Other Regulatory Assets."

In June 2006, the Mississippi PSC issued an order based upon a stipulation between Mississippi Power and the Mississippi Public Utilities Staff. The stipulation and the associated order certified actual storm restoration costs relating to Hurricane Katrina through April 30, 2006 of $267.9 million and affirmed estimated additional costs through December 31, 2007 of $34.5 million, for total storm restoration costs of $302.4 million which was net of insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million. Of the total amount, $292.8 million applies to Mississippi Power's retail jurisdiction. The order directed Mississippi Power to file an application with the Mississippi Development Authority (MDA) for a Community Development Block Grant (CDBG). Mississippi Power filed the CDBG application with the MDA in September 2006. On October 30, 2006, Mississippi Power received from the MDA a CDBG in the amount of $276.4 million. Mississippi Power has appropriately allocated and applied these CDBG proceeds to both retail and wholesale storm restoration cost recovery.

Mississippi Power filed an application for a financing order with the Mississippi PSC on July 3, 2006 for restoration costs under the state bond program. On October 27, 2006, the Mississippi PSC issued a financing order that authorizes the issuance of $121.2 million of system restoration bonds. This amount includes $25.2 million for the retail storm recovery costs not covered by the CDBG, $60 million for a property damage reserve, and $36 million for the retail portion of the construction of the storm operations facility. The bonds will be issued by the Mississippi Development Bank on behalf of the State of Mississippi and will be reported as liabilities by the State of Mississippi. Periodic true-up mechanisms will be structured to comply with terms and requirements of the legislation. Details regarding the issuance of the bonds have not been finalized. The final outcome of this matter cannot now be determined.

As of December 31, 2006, Mississippi Power's under recovered balance in the property damage reserve account totaled approximately $4.7 million which is included in the balance sheets herein under "Current Assets."

In July 2006, the Florida PSC issued its order approving a stipulation and settlement between Gulf Power and several consumer groups that resolved all matters relating to Gulf Power's request for recovery of incurred costs for storm-recovery activities and the replenishment of Gulf Power's property damage reserve. The order provides for an extension of the storm-recovery surcharge currently being collected by Gulf Power for an additional 27 months, expiring in June 2009. According to the stipulation, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by Gulf Power through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve. The annual accrual to the reserve of $3.5 million and Gulf Power's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. Gulf Power made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of a March 2005 agreement regarding Hurricane Ivan costs that established the existing surcharge, Gulf Power agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the stipulation do not alter or affect that portion of the prior agreement. According to the order, in the case of future storms, if Gulf Power incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, Gulf Power will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. Gulf Power would then petition the Florida PSC for full recovery through an additional surcharge or other cost recovery mechanism.

As of December 31, 2006, Gulf Power's unrecovered balance in the property damage reserve totaled approximately $45.7 million, of which approximately $28.8 million and $16.9 million, respectively, are included in the balance sheets herein under "Current Assets" and "Deferred Charges and Other Assets."

At Alabama Power, operation and maintenance expenses associated with Hurricane Ivan were $57.8 million. In 2005, Alabama Power received Alabama PSC approvals to return certain regulatory liabilities to the retail customers. These orders also allowed Alabama Power to simultaneously recover from customers accruals of approximately $48 million primarily to offset the costs of Hurricane Ivan and restore a positive balance in the natural disaster reserve. The combined effect of these orders had no impact on net income in 2005.

In December 2005, the Alabama PSC approved a separate rate rider to recover Alabama Power's $51 million of deferred Hurricane Dennis and Katrina operation and maintenance costs over a two-year period and to replenish its reserve to a target balance of $75 million over a five-year period.

As of December 31, 2006, Alabama Power had recovered $49.5 million of the costs allowed for storm-recovery activities, of which $34.5 million was a reduction in the deficit balance in the natural disaster reserve account related to costs deferred from previous storms. The remaining under recovered balance in the property damage reserve account totaled approximately $16.8 million at December 31, 2006 and is included in the balance sheets herein under "Current Assets." The remaining $15.0 million collected was used to establish the target reserve for future storms. The balance in the target reserve, reduced for current year activity, was $13.2 million at December 31, 2006 and is included in the balance sheets herein under "Other Regulatory Liabilities."

See Notes 1 and 3 to the financial statements under "Storm Damage Reserves" and "Storm Damage Cost Recovery," respectively, for additional information on these reserves. The final outcome of these matters cannot now be determined.

Mirant Matters

Mirant was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and selected other countries. It was a wholly-owned subsidiary of Southern Company until its initial public offering in October 2000. In April 2001, Southern Company completed a spin-off to its shareholders of its remaining ownership and Mirant became an independent corporate entity.

In July 2003, Mirant and certain of its affiliates filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code. In January 2006, Mirant's plan of reorganization became effective, and Mirant emerged from bankruptcy. As part of the plan, Mirant transferred substantially all of its assets and its restructured debt to a new corporation that adopted the name Mirant Corporation (Reorganized Mirant). Southern Company has certain contingent liabilities associated with guarantees of contractual commitments made by Mirant's subsidiaries discussed in Note 7 to the financial statements under "Guarantees" and with various lawsuits discussed in Note 3 to the financial statements under "Mirant Matters."

In December 2004, as a result of concluding an IRS audit for the tax years 2000 and 2001, Southern Company paid $39 million in additional tax and interest for issues related to Mirant tax items. Under the terms of the separation agreements entered into in connection with the spin-off, Mirant agreed to indemnify Southern Company for costs associated with these tax items and additional IRS assessments. However, as a result of Mirant's bankruptcy, Southern Company sought reimbursement as an unsecured creditor in the Chapter 11 proceeding. Based on management's assessment of the collectibility of the $39 million receivable, Southern Company has reserved approximately $13.7 million. In December 2006, Southern Company received approximately $23 million in tax refunds from the IRS related to Mirant tax items.

Additional refunds are expected. The amount of any unsecured claim ultimately allowed with respect to Mirant tax items is expected to be reduced dollar-for-dollar by the amount of all refunds received from the IRS by Southern Company.

If Southern Company is ultimately required to make any additional payments either with respect to the IRS audit or its contingent obligations under guarantees of Mirant subsidiaries, Mirant's indemnification obligation to Southern Company for these additional payments, if allowed, would constitute unsecured claims against Mirant, entitled to stock in Reorganized Mirant. See Note 3 to the financial statements under "Mirant Matters – Mirant Bankruptcy."

In June 2005, Mirant, as a debtor in possession, and The Official Committee of Unsecured Creditors of Mirant Corporation filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006, and May 2006. The third amended complaint (the complaint) alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company prior to the spin-off. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach fiduciary duties to its creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under theories of restitution, unjust enrichment, and alter ego. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7 to the financial statements) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in June 2006.

In January 2006, MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant, was substituted as plaintiff. In February 2006, the Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia was granted. On May 19, 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts in the complaint. On December 11, 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims were barred; all other claims in the complaint may proceed. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. See Note 3 to the financial statements under "Mirant Matters – MC Asset Recovery Litigation" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Income Tax Matters

Leveraged Lease Transactions

Southern Company undergoes audits by the IRS for each of its tax years. The IRS has completed its audits of Southern Company's consolidated federal income tax returns for all years through 2003. Southern Company participates in four international leveraged lease transactions and receives federal income tax deductions for depreciation and amortization, as well as interest on related debt. The IRS proposed to disallow the tax losses for one of these leases (a lease-in-lease-out, or LILO) in connection with its audit of 1997 through 2001. In October 2004, Southern Company submitted the issue to the IRS appeals division and in February 2005 reached a negotiated settlement with the IRS, which is now final.

In connection with its audit of 2000 and 2001, the IRS also challenged Southern Company's deductions related to three other international lease (sale-in-lease-out, or SILO) transactions. In the third quarter 2006, Southern Company paid the full amount of the disputed tax and the applicable interest on the SILO issue for tax years 2000-2001 and filed a claim for refund which has been denied by the IRS. The disputed tax amount is $79 million and the related interest is approximately $24 million for these tax years. This payment, and the subsequent IRS disallowance of the refund claim, closed the issue with the IRS and Southern Company plans to proceed with litigation. The IRS has also raised the SILO issues for tax years 2002 and 2003. The estimated amount of disputed tax and interest for these years is approximately $83 million and $15 million, respectively. The tax and interest for these tax years was paid to the IRS in the fourth quarter 2006. Southern Company has accounted for both payments in 2006 as deposits, as management believes no additional tax or interest liabilities have been incurred.

Although the payment of the tax liability did not affect Southern Company's results of operations under accounting standards in effect through December 31, 2006, it did impact cash flow. For tax years 2000 through 2006, Southern Company has claimed $284 million in tax benefits related to these SILO transactions challenged by the IRS. See Note 1 to the financial statements under "Leveraged Leases" for additional information. Southern Company believes these transactions are valid leases for U.S. tax purposes and thus the related deductions are allowable. The Company will continue to defend this position through administrative appeals or litigation. The ultimate outcome of these matters cannot now be determined.

In July 2006, the Financial Accounting Standards Board (FASB) released new interpretations for the accounting for both leveraged leases and uncertain tax positions that were adopted January 1, 2007. For the LILO transaction settled with the IRS in February 2005, the leveraged leases accounting interpretation requires that Southern Company recognize a cumulative effect reduction to beginning 2007 retained earnings of approximately $17 million at adoption and change the timing of income recognized under the lease.

For the SILO transactions which are the subject of pending litigation, Southern Company is continuing to evaluate the impact of the new interpretations but estimates that the reduction to retained earnings in 2007 could be approximately $115 million to $135 million. The impact on Southern Company's net income of these accounting interpretations would also be dependent on the outcome of the pending litigation or changes in assumptions related to uncertain tax positions but could be significant, and potentially material.

Synthetic Fuel Tax Credits

Southern Company had investments in two entities that produce synthetic fuel and receive tax credits under Section 45K (formerly Section 29) of the Internal Revenue Code of 1986, as amended (Internal Revenue Code). During 2006, as discussed below, Southern Company's interest in one of the synthetic fuel entities was terminated. In accordance with Section 45K of the Internal Revenue Code, these tax credits are subject to limitation as the annual average price of oil (as determined by the U.S. Department of Energy (DOE)) increases over a specified, inflation-adjusted dollar amount published in the spring of the subsequent year. Southern Company, along with its partners in these investments, has continued to monitor oil prices. Reserves against these tax credits of $32 million were recorded in 2006 due to projected phase-outs of the credits in 2006 as a result of higher oil prices. Synthetic fuel tax credits will end December 31, 2007.

In May 2006, production at one of the synthetic fuel investments was idled due to continued uncertainty over the value of tax credits. In addition, Southern Company entered into an agreement in June 2006 which terminated its ownership interest in its other synthetic fuel investment, effective July 1, 2006. Also, during 2006, Southern Company entered into derivative transactions designed to reduce its exposure to changes in the value of tax credits associated with its synthetic fuel investments. These derivative transactions were marked to market through other income (expense), net. As a result of these actions and the projected continued phase out of tax credits because of high oil prices, the investments in these two synthetic fuel entities were considered fully impaired and approximately $16 million was written off and is reflected in the line item "Impairment loss on equity method investments" on the statements of income herein. In September 2006, due to reduced oil prices in the third quarter, production was restarted at the synthetic fuel facility in which Southern Company still has an ownership interest. In October 2006, Southern Company entered into additional derivative transactions to reduce its exposure to the potential phase-out of these income tax credits in 2007. Subsequent to December 31, 2006, the Company entered into additional derivative transactions to further reduce its exposure to potential phase-out of tax credits in 2007. See Note 6 to the financial statements under "Financial Instruments" for additional information regarding the impact of these derivatives. The final outcome of these matters cannot now be determined.

Construction Projects

Integrated Coal Gasification Combined Cycle

In December 2005, Southern Power and the Orlando Utilities Commission (OUC) executed definitive agreements for development of an integrated coal gasification combined cycle (IGCC) 285-megawatt project in Orlando, Florida. The definitive agreements provide that Southern Power will own at least 65 percent of the gasifier portion of the IGCC project. OUC will own the remainder of the gasifier portion and 100 percent of the combined cycle portion of the IGCC project. OUC will purchase all of the gasifier capacity from Southern Power once the plant is in commercial operation. Southern Power will construct the project and manage its operation after construction is completed. In February 2006, Southern Power signed a cooperative agreement with the DOE that provides up to $235 million in grant funding for the gasification portion of this project. The IGCC project is subject to National Environmental Policy Act review as well as state environmental review, requires certain regulatory approvals, and is expected to begin commercial operation in 2010. The total cost related to the IGCC project is currently being reviewed, and may be higher than earlier estimates due to increases in commodity costs and increased market demand for labor. Southern Power had spent $7.8 million as of December 31, 2006. Southern Power has the option under the agreements to end its participation in the IGCC project at the end of the project definition phase which is expected to be during 2007.

In June 2006, Mississippi Power filed an application with the DOE for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The proposed project is an advanced coal gasification facility located in Kemper County, Mississippi that would use locally mined lignite coal. The proposed 693 megawatt plant, excluding the mine cost, is expected to require an approximate investment of $1.5 billion and is expected to be completed in 2013. The DOE subsequently certified the project and in November 2006 the IRS allocated Internal Revenue Code Section 48A tax credits to Mississippi Power of $133 million. The utilization of these credits is dependent upon meeting the certification requirements for the project under the Internal Revenue Code. The plant would use an air-blown IGCC technology that generates power from low-rank coals and coals with high moisture or high ash content. These coals, which include lignite, make up half the proven U.S. and worldwide coal reserves. Mississippi Power is still undergoing a feasibility assessment of the project which could take up to two years. Approval by various regulatory agencies, including the Mississippi PSC, will also be required if the project proceeds.

The final outcome of these matters cannot now be determined.

Nuclear

On August 15, 2006, as part of a potential expansion of Plant Vogtle, Georgia Power and Southern Nuclear Operating Company, Inc. (SNC) filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit (ESP) on behalf of the owners of Plant Vogtle. In addition, Georgia Power and SNC notified the NRC of their intent to apply for a combined construction and operating license (COL) in 2008. Ownership agreements have been signed with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on these co-owners. In June 2006, the Georgia PSC approved Georgia Power's request to establish an accounting order that would allow Georgia Power to defer for future recovery the ESP and COL costs, of which Georgia Power's portion is estimated to total approximately $51 million over the next four years. At this point, no final decision has been made regarding actual construction. Any new generation resource must be certified by the Georgia PSC in a separate proceeding.

On March 16, 2006, a subsidiary of Southern Company entered into a development agreement with Duke Energy Corporation (Duke Energy) to evaluate the potential construction of a new two-unit nuclear plant at a jointly owned site in Cherokee County, South Carolina. If constructed, Southern Company would own an interest in Unit 1, representing approximately 500 megawatts. Duke Energy will be the developer and licensed operator of any plant built at the site.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy plans to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs, then to choose one of the applications and file it for NRC review and approval. The COL ultimately is expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Southern Company is also exploring other possibilities relating to nuclear power projects, both on its own or in partnership with other utilities. The final outcome of these matters cannot now be determined.

Other Matters

Southern Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has discussed the development and selection of the critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprise approximately 93 percent of Southern Company's total earnings for 2006, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

Southern Company and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject them to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which Southern Company or its subsidiaries may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which Southern Company or its subsidiaries may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, and power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Stock Options

On January 1, 2006, Southern Company adopted FASB Statement No. 123(R), "Share-Based Payment," using the modified prospective method. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, Southern Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, Southern Company recorded an additional prepaid pension asset of $520 million with respect to its overfunded defined benefit plan and additional liabilities of $45 million and $553 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. Additionally, SFAS No. 158 will require Southern Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Southern Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on Southern Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. Southern Company adopted FIN 48 effective January 1, 2007. The impact on Southern Company's financial statements is estimated to be a reduction to retained earnings of $15 million to $25 million.

Leveraged Leases

In July 2006, the FASB issued FASB Staff Position No. FAS 13-2, "Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction" (FSP 13-2). This staff position amends FASB Statement No. 13, "Accounting for Leases" to require recalculation of the rate of return and the allocation of income whenever the projected timing of the income tax cash flows generated by a leveraged lease is revised. Southern Company adopted FSP 13-2 effective January 1, 2007. This adoption required Southern Company to recognize a cumulative effect of an approximate $17 million decrease to retained earnings related to the LILO transaction settled with the IRS in February 2005. The estimated impact of the adoption related to the SILO transactions is a reduction to retained earnings of approximately $100 million to $115 million. See FUTURE EARNINGS POTENTIAL — "Income Tax Matters — Leveraged Lease Transactions" above and Note 3 to the financial statements under "Income Tax Matters" herein for further details about the effect of FSP 13-2.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. Southern Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Southern Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2006. Net cash flow from operations increased from 2005 by $290 million. The increase was primarily the result of decreases in under recovered fuel cost receivables due to higher allowed fuel recovery rates, decreases in under recovered storm restoration costs, and decreases in accounts payable from year-end 2005 amounts that included substantial hurricane-related expenditures, partially offset by increases in fossil fuel inventory. The $165 million decrease from 2005 to 2004 resulted primarily from higher fuel costs at the traditional operating companies, partially offset by increases in base rates and fuel recovery rates. See FUTURE EARNINGS POTENTIAL — "PSC Matters — Fuel Cost Recovery" and "Storm Damage Cost Recovery" for additional information.

Significant balance sheet changes include an increase in notes payable of $683 million primarily to meet Southern Company's short-term financing needs until longer term financing is secured, an increase in securities due within one year of $517 million for debt maturing within the next year, and an increase in property, plant, and equipment of $1.6 billion. The majority of funds needed for property additions were provided from operating activities. The implementation of SFAS No. 158 resulted in significant balance sheet changes and accounts for a large portion of the increases in prepaid pension assets of $527 million, other regulatory assets of $417 million, employee benefit obligations of $637 million, and other regulatory liabilities of $471 million.

At the close of 2006, the closing price of Southern Company's common stock was $36.86 per share, compared with book value of $15.24 per share. The market-to-book value ratio was 242 percent at the end of 2006, compared with 240 percent at year-end 2005.

Southern Company, each of the traditional operating companies, and Southern Power, have received investment grade ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and/or preference stock. SCS has an investment grade corporate credit rating.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2007, as well as in subsequent years, will be contingent on Southern Company's investment opportunities. The Company does not currently anticipate any equity offerings in 2007 outside of its existing stock option plan, the employee savings plan, and the Southern Investment Plan.

The traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, and short-term borrowings. See Note 3 to the financial statements under "Storm Damage Cost Recovery" for information regarding additional options that Mississippi Power may pursue for recovering storm damage costs. However, the type and timing of any financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. In addition, the issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to the capital markets, including commercial paper programs, to meet liquidity needs.

At December 31, 2006, Southern Company and its subsidiaries had approximately $167 million of cash and cash equivalents and $3.3 billion of unused credit arrangements with banks, of which $656 million expire in 2007 and $2.7 billion expire in 2008 and beyond. Of the $2.7 billion expiring in 2008 and beyond, $2.4 billion does not expire until 2011. Approximately $79 million of the credit facilities expiring in 2007 allow for the execution of term loans for an additional two-year period, and $343 million allow for the execution of one-year term loans. Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Financing Activities

During 2006, Southern Company and its subsidiaries issued $1.4 billion of senior notes, $154 million of obligations related to pollution control revenue bonds, and $150 million of preference stock. Interest rate hedges of $1.1 billion notional amount were settled at a gain of $2.7 million related to the issuances. The security issuances were used to redeem or extinguish $1.2 billion of long-term debt, to redeem $169 million of obligations related to pollution control revenue bonds, to redeem $15 million of preferred stock, to fund Southern Company's ongoing construction program, and for general corporate purposes. In the second and fourth quarters of 2006, Alabama Power issued to Southern Company a total of 3 million shares of Alabama Power common stock at $40.00 per share. The proceeds of $120 million were used by Alabama Power to repay short-term indebtedness and for other general corporate purposes.

Subsequent to December 31, 2006, Southern Company issued $500 million of senior notes. The proceeds from the sale of the senior notes were used by the Company to repay a portion of its outstanding short-term indebtedness, a portion of which was incurred to extinguish the 8.19% and 8.14% Southern Company Capital Funding Junior Subordinated Notes, and for other general corporate purposes. Also subsequent to December 31, 2006, Georgia Power entered into interest rate swap transactions with a notional amount of $375 million, in order to reduce exposure to interest rate risk. The transactions will be settled over the next two years as the underlying debt is issued, and any resulting gain or loss will be amortized over a 10-year period.

On January 19, 2007, Gulf Power issued to Southern Company 800,000 shares of Gulf Power's common stock, without par value, for $80 million. The proceeds were used by Gulf Power to repay short-term indebtedness and for other general corporate purposes. On February 6, 2007, Alabama Power issued $200 million in senior notes. The proceeds from the sale of the senior notes were used to repay a portion of Alabama Power's outstanding short-term debt and for other general corporate purposes.

Off-Balance Sheet Financing Arrangements

In 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), a limited partnership whose investors are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50 percent of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease also provides for a residual value guarantee, approximately 73 percent of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the assets. See Note 7 to the financial statements under "Operating Leases" for additional information.

Credit Rating Risk

Southern Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. These contracts are primarily for physical electricity purchases and sales. At December 31, 2006, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $291 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $711 million. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Southern Company's operating subsidiaries are also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for Alabama Power and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, Southern Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to change in interest rates, the Company enters into forward starting interest rate swaps that have been designated as hedges. The swaps outstanding at December 31, 2006 have a notional amount of $725 million and are related to anticipated debt issuances over the next year. The weighted average interest rate on $1.7 billion of long-term variable interest rate exposure that has not been hedged at January 1, 2007 was 5.1 percent. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $17.9 million at January 1, 2007. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Due to cost-based rate regulations, the traditional operating companies have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts generally shift substantially all fuel cost responsibility to the purchaser. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies and Southern Power enter into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into similar contracts for natural gas purchases. The traditional operating companies have implemented fuel-hedging programs at the instruction of their respective state PSCs.

The changes in fair value of energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in millions)	
Contracts beginning of year	$ 101	$ 11
Contracts realized or settled	93	(106)
New contracts at inception	–	–
Changes in valuation techniques	–	–
Current period changes(a)	(276)	196
Contracts end of year	$ (82)	$ 101

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

Source of 2006 Year-End Valuation Prices			
	Total	Maturity	
	Fair Value	2007	2008-2009
		(in millions)	
Actively quoted	$(86)	$(79)	$(7)
External sources	4	4	–
Models and other	–	–	–
Contracts end of year	$(82)	$(75)	$(7)

Unrealized gains and losses from mark-to-market adjustments on derivative contracts related to the traditional operating companies' fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the traditional operating companies' fuel cost recovery clauses. In addition, unrealized gains and losses on energy-related derivatives used by Southern Power to hedge anticipated purchases and sales are deferred in other comprehensive income. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts was reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	$(85)
Accumulated other comprehensive income	3
Net income	–
Total fair value	$(82)

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

Southern Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. Southern Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To reduce Southern Company's exposure to changes in the value of synthetic fuel tax credits, which are impacted by changes in oil prices, the Company has entered into derivative transactions indexed to oil prices. Because these transactions are not designated as hedges, the gains and losses are recognized in the statements of income as incurred. For 2006 and 2005, the fair value losses recognized in income to mark the transactions to market were $32 million and $7 million, respectively. In January 2007, Southern Company entered into additional derivative transactions with net initial premiums paid of $3 million to further reduce its exposure to the potential phase-out of these income tax credits in 2007. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of Southern Company is currently estimated to be $3.9 billion for 2007, $4.5 billion for 2008, and $4.8 billion for 2009. Environmental expenditures included in these amounts are $1.66 billion, $1.65 billion, and $1.27 billion for 2007, 2008, and 2009, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and 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.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[a] –					
Principal	$ 1,418	$ 1,103	$ 615	$10,803	$13,939
Interest	738	1,307	1,205	10,572	13,822
Other derivative obligations[b] –					
Commodity	119	10	-	-	129
Interest	6	-	-	-	6
Preferred and preference stock dividends[c]	41	81	81	-	203
Operating leases	135	224	160	186	705
Purchase commitments[d] –					
Capital[e]	3,790	9,050	-	-	12,840
Coal	3,294	4,329	1,644	2,221	11,488
Nuclear fuel	120	231	305	236	892
Natural gas[f]	1,347	1,902	809	2,740	6,798
Purchased power	173	374	351	890	1,788
Long-term service agreements	74	156	193	1,231	1,654
Trusts –					
Nuclear decommissioning	7	14	14	110	145
Postretirement benefits[g]	41	91	-	-	132
Total	$11,303	$18,872	$5,377	$28,989	$64,541

(a) All amounts are reflected based on final maturity dates. On February 1, 2007, $400 million aggregate principal amount of long-term debt matured. The maturity was funded with short-term borrowings. Southern Company and its subsidiaries plan to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(d) Southern Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2006, 2005, and 2004 were $3.5 billion, $3.5 billion, and $3.3 billion, respectively.

(e) Southern Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) Southern Company forecasts postretirement trust contributions over a three-year period. No contributions related to Southern Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from Southern Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales growth, customer growth, storm damage cost recovery and repairs, fuel cost recovery, environmental regulations and expenditures, earnings growth, dividend payout ratios, access to sources of capital, projections for postretirement benefit trust contributions, synthetic fuel investments, financing activities, completion of construction projects, impacts of adoption of new accounting rules, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax, and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, IRS audits, and Mirant matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of Southern Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- fluctuations in the level of oil prices;
- the level of production, if any, by the synthetic fuel operations at Carbontronics Synfuels Investors LP and Alabama Fuel Products, LLC for fiscal year 2007;
- 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 Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Southern Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in millions)	
Operating Revenues:			
Retail revenues	**$11,801**	$11,165	$ 9,732
Sales for resale	**1,822**	1,667	1,341
Other electric revenues	**465**	446	392
Other revenues	**268**	276	264
Total operating revenues	**14,356**	13,554	11,729
Operating Expenses:			
Fuel	**5,152**	4,495	3,399
Purchased power	**543**	731	643
Other operations	**2,423**	2,394	2,263
Maintenance	**1,096**	1,116	1,027
Depreciation and amortization	**1,200**	1,176	949
Taxes other than income taxes	**718**	680	627
Total operating expenses	**11,132**	10,592	8,908
Operating Income	**3,224**	2,962	2,821
Other Income and (Expense):			
Allowance for equity funds used during construction	**50**	51	47
Interest income	**41**	36	27
Equity in losses of unconsolidated subsidiaries	**(57)**	(119)	(95)
Leveraged lease income	**69**	74	70
Impairment loss on equity method investments	**(16)**	-	-
Interest expense, net of amounts capitalized	**(744)**	(619)	(540)
Interest expense to affiliate trusts	**(122)**	(128)	(100)
Distributions on mandatorily redeemable preferred securities	**-**	-	(27)
Preferred and preference dividends of subsidiaries	**(34)**	(30)	(30)
Other income (expense), net	**(56)**	(41)	(59)
Total other income and (expense)	**(869)**	(776)	(707)
Earnings From Continuing Operations Before Income Taxes	**2,355**	2,186	2,114
Income taxes	**781**	595	585
Earnings From Continuing Operations	**1,574**	**1,591**	**1,529**
Earnings from discontinued operations, net of income taxes of $(1), $-, and $2 for 2006, 2005, and 2004, respectively	**(1)**	-	3
Consolidated Net Income	**$ 1,573**	**$ 1,591**	**$ 1,532**
Common Stock Data:			
Earnings per share from continuing operations –			
Basic	**$ 2.12**	$ 2.14	$ 2.07
Diluted	**2.10**	2.13	2.06
Earnings per share including discontinued operations –			
Basic	**$ 2.12**	$ 2.14	$ 2.07
Diluted	**2.10**	2.13	2.06
Average number of shares of common stock outstanding – (in millions)			
Basic	**743**	744	739
Diluted	**748**	749	743
Cash dividends paid per share of common stock	**$ 1.535**	$ 1.475	$ 1.415

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2006, 2005, and 2004
Southern Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 1,573**	$ 1,591	$ 1,532
Adjustments to reconcile consolidated net income to net cash provided from operating activities --			
Depreciation and amortization	**1,421**	1,398	1,161
Deferred income taxes and investment tax credits	**202**	499	559
Allowance for equity funds used during construction	**(50)**	(51)	(47)
Equity in losses of unconsolidated subsidiaries	**57**	119	95
Leveraged lease income	**(69)**	(74)	(70)
Pension, postretirement, and other employee benefits	**46**	(6)	(22)
Stock option expense	**28**	-	-
Tax benefit of stock options	**4**	50	31
Derivative fair value adjustments	**32**	8	2
Hedge settlements	**13**	(19)	(10)
Storm damage accounting order	**-**	48	-
Other, net	**46**	(30)	35
Changes in certain current assets and liabilities --			
Receivables	**(69)**	(1,045)	(392)
Fossil fuel stock	**(246)**	(110)	(8)
Materials and supplies	**7**	(78)	(31)
Other current assets	**73**	(1)	9
Accounts payable	**(173)**	71	29
Hurricane Katrina grant proceeds	**120**	-	-
Accrued taxes	**(103)**	28	(109)
Accrued compensation	**(24)**	13	(23)
Other current liabilities	**(68)**	119	(46)
Net cash provided from operating activities	**2,820**	2,530	2,695
Investing Activities:			
Property additions	**(2,994)**	(2,370)	(2,022)
Nuclear decommissioning trust fund purchases	**(751)**	(606)	(810)
Nuclear decommissioning trust fund sales	**743**	596	781
Proceeds from property sales	**150**	10	6
Hurricane Katrina capital grant proceeds	**153**	-	-
Investment in unconsolidated subsidiaries	**(64)**	(115)	(97)
Cost of removal net of salvage	**(90)**	(128)	(75)
Other	**19**	(16)	(41)
Net cash used for investing activities	**(2,834)**	(2,629)	(2,258)
Financing Activities:			
Increase (decrease) in notes payable, net	**683**	831	(141)
Proceeds --			
Long-term debt	**1,564**	1,608	1,861
Mandatorily redeemable preferred securities	**-**	-	200
Preferred and preference stock	**150**	55	175
Common stock	**137**	213	124
Redemptions --			
Long-term debt	**(967)**	(1,285)	(1,246)
Long-term debt to affiliate trusts	**(399)**	-	-
Mandatorily redeemable preferred securities	**-**	-	(240)
Preferred and preference stock	**(15)**	(4)	(28)
Common stock repurchased	**-**	(352)	-
Payment of common stock dividends	**(1,140)**	(1,098)	(1,045)
Other	**(34)**	(35)	(40)
Net cash (used for) provided from financing activities	**(21)**	(67)	(380)
Net Change in Cash and Cash Equivalents	**(35)**	(166)	57
Cash and Cash Equivalents at Beginning of Year	**202**	368	311
Cash and Cash Equivalents at End of Year	**$ 167**	$ 202	$ 368

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2006 and 2005
Southern Company and Subsidiary Companies 2006 Annual Report

Assets	2006	2005
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 167	$ 202
Receivables --		
Customer accounts receivable	943	868
Unbilled revenues	283	304
Under recovered regulatory clause revenues	517	755
Other accounts and notes receivable	330	410
Accumulated provision for uncollectible accounts	(35)	(38)
Fossil fuel stock, at average cost	675	403
Materials and supplies, at average cost	648	666
Vacation pay	121	117
Prepaid expenses	128	129
Other	242	389
Total current assets	4,019	4,205
Property, Plant, and Equipment:		
In service	45,486	43,578
Less accumulated depreciation	16,582	15,727
	28,904	27,851
Nuclear fuel, at amortized cost	317	262
Construction work in progress	1,871	1,367
Total property, plant, and equipment	31,092	29,480
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,058	954
Leveraged leases	1,139	1,082
Other	296	337
Total other property and investments	2,493	2,373
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	895	937
Prepaid pension costs	1,549	1,022
Unamortized debt issuance expense	172	162
Unamortized loss on reacquired debt	293	309
Deferred under recovered regulatory clause revenues	845	531
Other regulatory assets	936	519
Other	564	339
Total deferred charges and other assets	5,254	3,819
Total Assets	$42,858	$39,877

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2006 and 2005

Southern Company and Subsidiary Companies 2006 Annual Report

Liabilities and Stockholders' Equity	2006	2005
	(in millions)	
Current Liabilities:		
Securities due within one year	$ 1,418	$ 901
Notes payable	1,941	1,258
Accounts payable	1,081	1,229
Customer deposits	249	220
Accrued taxes --		
Income taxes	110	104
Other	391	319
Accrued interest	184	204
Accrued vacation pay	151	144
Accrued compensation	444	459
Other	384	402
Total current liabilities	6,353	5,240
Long-term Debt (See accompanying statements)	10,942	10,958
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	1,561	1,888
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	5,989	5,736
Deferred credits related to income taxes	291	311
Accumulated deferred investment tax credits	503	527
Employee benefit obligations	1,567	930
Asset retirement obligations	1,137	1,117
Other cost of removal obligations	1,300	1,295
Other regulatory liabilities	794	323
Other	306	267
Total deferred credits and other liabilities	11,887	10,506
Total Liabilities	30,743	28,592
Preferred and Preference Stock of Subsidiaries (See accompanying statements)	744	596
Common Stockholders' Equity (See accompanying statements)	11,371	10,689
Total Liabilities and Stockholders' Equity	$42,858	$39,877
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31, 2006 and 2005

Southern Company and Subsidiary Companies 2006 Annual Report

		2006	2005	2006	2005
		(in millions)		(percent of total)	
Long-Term Debt of Subsidiaries:					
First mortgage bonds –					
Maturity	Interest Rates				
2006	6.50% to 6.90%	$ -	$ 45		
Total first mortgage bonds		-	45		
Long-term senior notes and debt –					
Maturity	Interest Rates				
2006	2.65% to 6.20%	-	674		
2007	3.50% to 7.13%	**1,204**	1,207		
2008	2.54% to 6.55%	**460**	461		
2009	4.10% to 7.00%	**127**	128		
2010	4.70%	**102**	102		
2011	4.00% to 5.10%	**302**	102		
2012 through 2046	4.35% to 8.12%	**6,730**	5,535		
Adjustable rates (at 1/1/07):					
2006	2.11%	-	27		
2007	5.624%	**169**	265		
2009	5.54% to 5.55%	**440**	440		
2010	6.23%	**221**	154		
Total long-term senior notes and debt		**9,755**	9,095		
Other long-term debt –					
Pollution control revenue bonds –					
Maturity	Interest Rates				
2006	5.25%	-	12		
2024	5.50%	-	3		
Variable rates (at 1/1/06):					
2015 through 2017	2.01% to 2.16%	-	90		
2012 through 2036	2.83% to 5.45%	**812**	850		
Variable rates (at 1/1/07):					
2011 through 2041	3.50% to 4.07%	**1,714**	1,586		
Total other long-term debt		**2,526**	2,541		
Capitalized lease obligations		**97**	110		
Unamortized debt (discount), net		**(18)**	(19)		
Total long-term debt (annual interest requirement – $643 million)		**12,360**	11,772		
Less amount due within one year		**1,418**	814		
Long-term debt excluding amount due within one year		**10,942**	10,958	**44.5%**	45.4%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2006 and 2005
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	2006	2005	2006	2005
	(in millions)		(percent of total)	
Long-term Debt Payable to Affiliated Trusts:				
Maturity — Interest Rates				
2027 through 2044 — 4.75% to 8.19%				
(annual interest requirement -- $95 million)	**1,561**	1,960		
Less amount due within one year	**-**	72		
Total long-term debt payable to affiliated trusts excluding amount due within one year	**1,561**	1,888	**6.3**	7.8
Preferred and Preference Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 5.44%				
Authorized - 10 million shares				
Outstanding - 1 million shares	**81**	96		
$1 par value -- 4.95% to 5.83%				
Authorized - 2006: 28 million shares				
Outstanding - 12 million shares: $25 stated value	**294**	294		
Outstanding - 1,250 shares: $100,000 stated value	**123**	123		
Non-cumulative preferred stock				
$25 par value -- 6.00% to 6.13%				
Authorized - 2006: 50 million shares				
- 2005: 4 million shares				
Outstanding - 2 million shares	**45**	44		
Preference stock				
Authorized - 2006: 50 million shares				
- 2005: 10 million shares				
Outstanding - $1 par value -- 5.63%	**147**	-		
- 2006: 6 million shares (non-cumulative)				
- 2005: 0 shares				
- $100 par or stated value -- 6.00%	**54**	54		
- 2006: 1 million shares (non-cumulative)				
- 2005: 1 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement -- $41 million)	**744**	611		
Less amount due within one year	**-**	15		
Preferred and preference stock of subsidiaries excluding amount due within one year	**744**	596	**3.0**	2.5
Common Stockholders' Equity:				
Common stock, par value $5 per share --	**3,759**	3,759		
Authorized - 1 billion shares				
Issued -- 2006: 752 million shares				
-- 2005: 752 million shares				
Treasury -- 2006: 5.6 million shares				
-- 2005: 10.4 million shares				
Paid-in capital	**1,096**	1,085		
Treasury, at cost	**(192)**	(359)		
Retained earnings	**6,765**	6,332		
Accumulated other comprehensive income (loss)	**(57)**	(128)		
Total common stockholders' equity	**11,371**	10,689	**46.2**	44.3
Total Capitalization	**$24,618**	$24,131	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

For the Years Ended December 31, 2006, 2005, and 2004
Southern Company and Subsidiary Companies 2006 Annual Report

	Common Stock				Accumulated Other Comprehensive Income (Loss)		
	Par Value	Paid-In Capital	Treasury	Retained Earnings	Continuing Operations	Discontinued Operations	Total
				(in millions)			
Balance at December 31, 2003	$3,675	$ 747	$ (4)	$ 5,343	$(115)	$ 2	$ 9,648
Net income	-	-	-	1,532	-	-	1,532
Other comprehensive income (loss)	-	-	-	-	(16)	(4)	(20)
Stock issued	34	122	-	-	-	-	156
Cash dividends	-	-	-	(1,044)	-	-	(1,044)
Other	-	-	(2)	8	-	-	6
Balance at December 31, 2004	3,709	869	(6)	5,839	(131)	(2)	10,278
Net income	-	-	-	1,591	-	-	1,591
Other comprehensive income	-	-	-	-	3	2	5
Stock issued	50	216	-	-	-	-	266
Stock repurchased, at cost	-	-	(352)	-	-	-	(352)
Cash dividends	-	-	-	(1,098)	-	-	(1,098)
Other	-	-	(1)	-	-	-	(1)
Balance at December 31, 2005	**3,759**	**1,085**	**(359)**	**6,332**	**(128)**	**-**	**10,689**
Net income	-	-	-	**1,573**	-	-	**1,573**
Other comprehensive income	-	-	-	-	**19**	-	**19**
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	-	**52**	-	**52**
Stock issued	-	**11**	**168**	-	-	-	**179**
Stock repurchased, at cost	-	-	-	-	-	-	-
Cash dividends	-	-	-	**(1,140)**	-	-	**(1,140)**
Other	-	-	**(1)**	-	-	-	**(1)**
Balance at December 31, 2006	**$3,759**	**$1,096**	**$(192)**	**$ 6,765**	**$ (57)**	**$ -**	**$11,371**

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Southern Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in millions)	
Consolidated Net Income	**$1,573**	$1,591	$1,532
Other comprehensive income (loss) - continuing operations:			
Change in additional minimum pension liability, net of tax of $10, $(6), and $(11), respectively	**18**	(11)	(20)
Change in fair value of marketable securities, net of tax of $4, $(2) and $4, respectively	**8**	(4)	6
Changes in fair value of qualifying hedges, net of tax of $(5), $7, and $(11), respectively	**(8)**	12	(16)
Less: Reclassification adjustment for amounts included in net income, net of tax of $-, $4, and $8, respectively	**1**	6	14
Total other comprehensive income (loss) -- continuing operations	**19**	3	(16)
Other comprehensive income (loss) -- discontinued operations:			
Changes in fair value of qualifying hedges, net of tax of $4 and $(1), respectively	**-**	6	(2)
Less: Reclassification adjustment for amounts included in net income, net of tax of $(3) and $(1), respectively	**-**	(4)	(2)
Total other comprehensive income (loss) -- discontinued operations	**-**	2	(4)
Consolidated Comprehensive Income	**$1,592**	$1,596	$1,512

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Company (the Company) is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and the subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

On January 4, 2006, Southern Company completed the sale of substantially all of the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary, including natural gas inventory, accounts receivable, and customer list, to Gas South, LLC, an affiliate of Cobb Electric Membership Corporation. As a result of the sale, Southern Company's financial statements and related information reflect Southern Company Gas as discontinued operations for all periods presented. For additional information, see Note 3 under "Southern Company Gas Sale."

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. All material intercompany items have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform with the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow accounting principles generally accepted in the United States and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Related Party Transactions

Alabama Power and Georgia Power purchase synthetic fuel from Alabama Fuel Products, LLC (AFP), an entity in which Southern Holdings held a 30 percent ownership interest until July 2006, when its ownership interest was terminated. Total fuel purchases through June 2006 and for the years 2005 and 2004 were $354 million, $507 million, and $409 million, respectively. Synfuel Services, Inc. (SSI), another subsidiary of Southern Holdings, provided fuel transportation services to AFP that were ultimately reflected in the cost of the synthetic fuel billed to Alabama Power and Georgia Power. In connection with these services, the related revenues of approximately $62 million, $83 million, and $82 million through June 2006 and for the years 2005 and 2004, respectively, have been eliminated against fuel expense in the financial statements. SSI also provided additional services to AFP, as well as to a related party of AFP. Revenues from these transactions totaled approximately $24 million, $40 million, and $24 million through June 2006 and for the years 2005 and 2004, respectively.

Subsequent to the termination of Southern Company's membership interest in AFP, Alabama Power and Georgia Power continued to purchase an additional $384 million in fuel from AFP in 2006. SSI continued to provide fuel transportation services of $62 million, which were eliminated against fuel expense in the financial statements. In 2006, SSI also provided other additional services to AFP and a related party of AFP totaling $21 million.

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). 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:

	2006	2005	Note
	(in millions)		
Deferred income tax charges	**$ 896**	$ 937	(a)
Asset retirement obligations-asset	**61**	81	(a)
Asset retirement obligations-liab	**(155)**	(139)	(a)
Other cost of removal obligations	**(1,300)**	(1,295)	(a)
Deferred income tax credits	**(293)**	(313)	(a)
Loss on reacquired debt	**293**	309	(b)
Vacation pay	**121**	117	(c)
Under recovered regulatory clause revenues	**411**	351	(d)
Building lease	**51**	52	(d)
Generating plant outage costs-asset	**56**	54	(d)
Under recovered storm damage costs	**89**	366	(d)
Fuel hedging-asset	**115**	24	(d)
Fuel hedging-liability	**(13)**	(127)	(d)
Other assets	**55**	56	(d)
Environmental remediation-asset	**57**	58	(d)
Environmental remediation-liab.	**(32)**	(36)	(d)
Deferred purchased power	**(38)**	(52)	(d)
Other liabilities	**(50)**	(32)	(d)
Plant Daniel capacity	**(6)**	(19)	(e)
Overfunded retiree benefit plans	**(508)**	-	(f)
Underfunded retiree benefit plans	**697**	-	(f)
Total	**$ 507**	$ 392	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Recorded and recovered or amortized as approved by the appropriate state PSCs.

(e) Amortized over a four-year period ending in 2007.

(f) Recovered and amortized over the average remaining service period which may range up to 21 years. See Note 2 under "Retirement Benefits."

In the event that a portion of a traditional operating company's operations is no longer subject to the provisions of SFAS No. 71, such company would be required to write off related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair value. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Alabama Power Retail Regulatory Matters," "Georgia Power Retail Regulatory Matters," and "Storm Damage Cost Recovery" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Retail fuel cost recovery mechanisms vary by each retail operating company, but in general, the process requires periodic filings with the appropriate state PSC. Alabama Power continuously monitors the under/over recovered balance and files for a revised fuel rate when management deems appropriate. Georgia Power is required to file a new fuel case no later than March 1, 2008. Gulf Power is required to notify the Florida PSC if the projected fuel revenue over or under recovery exceeds 10 percent of the projected fuel costs for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. Mississippi Power is required to file for an adjustment to the fuel cost recovery factor annually. See "Alabama Power Retail Regulatory Matters" and "Georgia Power Retail Regulatory Matters" in Note 3 for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes the cost of purchased emission allowances as they are used. Fuel expense also 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 $137 million in 2006, $134 million in 2005, and $134 million in 2004.

Nuclear Fuel Disposal Costs

Alabama Power and Georgia Power have contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

Also, the Energy Policy Act of 1992 established a Uranium Enrichment Decontamination and Decommissioning Fund, which has been funded in part by a special assessment on utilities with nuclear plants. This assessment was paid over a 15-year period; the final installment occurred in 2006. 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.

Property, Plant, and Equipment

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

Southern Company's property, plant, and equipment consisted of the following at December 31:

	2006	2005
	(in millions)	
Generation	$23,355	$22,490
Transmission	6,352	6,031
Distribution	12,484	11,894
General	2,510	2,393
Plant acquisition adjustment	40	41
Utility plant in service	44,741	42,849
IT equipment and software	226	211
Communications equipment	445	431
Other	74	87
Other plant in service	745	729
Total plant in service	$45,486	$43,578

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power accrues estimated nuclear refueling costs in advance of the unit's next refueling outage. Georgia Power defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0 percent in 2006, 2.9 percent in 2005, and 3.0 percent in 2004. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $16.2 billion and $15.3 billion at December 31, 2006 and 2005, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the three-year retail rate plan for Georgia Power ending December 31, 2007 (2004 Retail Rate Plan), Georgia Power was ordered to recognize Georgia PSC-certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. As a result of the regulatory adjustment, Georgia Power recognized $33 million in increased depreciation and amortization expense in 2005. Georgia Power recorded a credit to amortization of $14 million in 2006. Under its 2001 rate order, the Georgia PSC ordered Georgia Power to amortize $333 million, the cumulative balance of accelerated depreciation and amortization previously expensed, equally over three years as a credit to depreciation and amortization expense beginning January 2002. Georgia Power also was ordered to recognize new certified capacity costs in rates evenly over the same three-year period under the 2001 rate order. As a result of this regulatory adjustment, Georgia Power recorded a reduction in depreciation and amortization expense of $77 million in 2004. See Note 3 under "Georgia Power Retail Regulatory Matters" for additional information.

In May 2004, the Mississippi PSC approved Mississippi Power's request to reclassify 266 megawatts of Plant Daniel units 3 and 4 capacity to jurisdictional cost of service effective January 1, 2004 and authorized Mississippi Power to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. Mississippi Power is amortizing the related regulatory liability pursuant to the Mississippi PSC's order as follows: $17 million in 2004, $25 million in 2005, $13 million in 2006, and $6 million in 2007, resulting in increases to earnings in each of those years.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from 3 to 25 years. Accumulated depreciation for other plant in service totaled $405 million and $378 million at December 31, 2006 and 2005, respectively.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, Southern Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, Southern Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, Plants Farley, Hatch, and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2006 was $1.1 billion. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. In connection with the adoption of FIN 47, Southern Company also recorded additional asset retirement obligations (and assets) of approximately $153 million, primarily related to asbestos removal and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2006	2005
	(in millions)	
Balance beginning of year	**$1,117**	$ 903
Liabilities incurred	**8**	155
Liabilities settled	**(5)**	(2)
Accretion	**73**	61
Cash flow revisions	**(56)**	-
Balance end of year	**$1,137**	$1,117

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale.

The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. As the external trust funds are actively managed by unrelated parties with limited direction from the Company, the Company does not have the ability to choose to hold securities with unrealized losses until recovery. Through 2005, the Company considered other-than-temporary impairments to be immaterial. However, since the January 1, 2006 effective date of FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" (FSP No. 115-1), the Company considers all unrealized losses to represent other-than-temporary impairments. The adoption of FSP No. 115-1 had no impact on the results of operations, cash flows, or financial condition of the Company as all losses have been and continue to be recorded through a regulatory liability, whether realized, unrealized, or identified as other-than-temporary. Details of the securities held in these trusts at December 31 are as follows:

2006	Unrealized Gains	Other-than-Temporary Impairments	Fair Value
		(in millions)	
Equity	**$227.9**	**$(10.3)**	**$ 763.1**
Debt	**3.7**	**(2.1)**	**285.5**
Other	**-**	**-**	**8.9**
Total	**$231.6**	**$(12.4)**	**$1,057.5**

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$155.6	$(14.0)	$600.8
Debt	4.1	(2.4)	241.4
Other	17.0	-	111.4
Total	$176.7	$(16.4)	$953.6

The contractual maturities of debt securities at December 31, 2006 are as follows: $8.0 million in 2007; $70.5 million in 2008-2011; $85.2 million in 2012-2016; and $120.4 million thereafter.

Sales of the securities held in the trust funds resulted in $743.1 million, $596.3 million, and $781.3 million in 2006, 2005, and 2004, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were $39.8 million and $30.3 million, respectively, in 2006. Net realized gains were $22.5 million and $21.6 million in 2005 and 2004, respectively. Realized gains and other-than-temporary impairment losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and other-than-temporary impairment losses are considered non-cash transactions for purposes of the statements of cash flow.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the respective state PSCs. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. At December 31, 2006, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle
		(in millions)	
External trust funds,			
at fair value	$513	$344	$200
Internal reserves	28	-	1
Total	$541	$344	$201

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2003 for Plant Farley and in 2006 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plants Hatch and Vogtle:

	Plant Farley	Plant Hatch	Plant Vogtle
Decommissioning periods:			
Beginning year	2017	2034	2027
Completion year	2046	2061	2051
		(in millions)	
Site study costs:			
Radiated structures	$892	$544	$507
Non-radiated structures	63	46	67
Total	$955	$590	$574

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

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. Georgia Power will include the 2006 study estimates as part of the retail base rate case to be filed with the Georgia PSC by July 2007. The estimates used in current rates are $421 million and $326 million for Plants Hatch and Vogtle, respectively. Amounts expensed in 2006, 2005, and 2004 totaled $7 million, $7 million, and $27 million, respectively. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5 percent and 3.1 percent for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0 percent and 5.1 percent for Alabama Power and Georgia Power, respectively. Another significant assumption used was the change in the operating licenses for Plants Farley and Hatch. In January 2002, the NRC granted Georgia Power a 20-year extension of the licenses for both units at Plant Hatch, which permits the operation of units 1 and 2 until 2034 and 2038, respectively. In May 2005, the NRC granted Alabama Power a similar 20-year extension of the operating license for both units at Plant Farley. As a result of the license extensions, amounts previously contributed to the external trust funds for Plants Hatch and Farley are currently projected to be adequate to meet the decommissioning obligations.

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

In accordance with regulatory treatment, the traditional operating companies record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements.

Cash payments for interest totaled $875 million, $661 million, and $551 million in 2006, 2005, and 2004, respectively, net of amounts capitalized of $27 million, $21 million, and $36 million, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserves

Each traditional operating company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to transmission and distribution facilities and to generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $26 million in 2006 that is recoverable through base rates. Alabama Power, Gulf Power, and Mississippi Power also have discretionary authority from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2006, 2005, and 2004, such additional accruals totaled $3 million, $6 million, and $25 million, respectively. In October 2006, the Mississippi PSC ordered Mississippi Power to suspend all accruals to its retail property damage reserve pending the establishment of a new reserve limit. Mississippi Power made no discretionary accruals in 2006 as a result of the order. See Note 3 under "Storm Damage Cost Recovery" for additional information regarding the depletion of these reserves following Hurricanes Ivan, Dennis, and Katrina and the deferral of additional costs, as well as additional rate riders or other cost recovery mechanisms which have been or may be approved by the respective state PSCs to replenish these reserves.

Environmental Remediation Cost Recovery

Southern Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the subsidiaries may also incur substantial costs to clean up properties. Alabama Power, Gulf Power, and Mississippi Power have each received authority from their respective state PSCs to recover approved environmental compliance costs through specific retail rate clauses. Within limits approved by the state PSCs, these rates are adjusted annually.

Georgia Power continues to recover environmental costs through its base rates. Beginning in 2005, such rates include an annual accrual of $5.4 million for environmental remediation. Environmental remediation expenditures will be charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings. Under Georgia PSC ratemaking provisions, $22 million had previously been deferred in a regulatory liability account for use in meeting future environmental remediation costs of Georgia Power and is being amortized over a three-year period that began in January 2005.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $57.2 million as of December 31, 2006. These estimated costs relate to new regulations and more stringent site closure criteria by the Florida Department of Environmental Protection (FDEP) for impacts to groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery, as expended, through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

For Southern Company, the undiscounted environmental remediation liabilities balances as of December 31, 2006 and 2005 totaled $63 million and $62 million, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, and the credit quality of the lessees.

Southern Company's net investment in domestic leveraged leases consists of the following at December 31:

	2006	2005
	(in millions)	
Net rentals receivable	**$ 497**	$ 509
Unearned income	**(261)**	(280)
Investment in leveraged leases	**236**	229
Deferred taxes arising from leveraged leases	**(133)**	(59)
Net investment in leveraged leases	**$ 103**	$ 170

A summary of the components of income from domestic leveraged leases is as follows:

	2006	2005	2004
		(in millions)	
Pretax leveraged lease income	**$20**	$ 23	$17
Income tax expense	**(9)**	(11)	(8)
Net leveraged lease income	**$11**	$ 12	$ 9

Southern Company's net investment in international leveraged leases consists of the following at December 31:

	2006	2005
	(in millions)	
Net rentals receivable	**$1,299**	$1,298
Unearned income	**(396)**	(445)
Investment in leveraged leases	**903**	853
Deferred taxes arising from leveraged leases	**(492)**	(351)
Net investment in leveraged leases	**$ 411**	$ 502

A summary of the components of income from international leveraged leases is as follows:

	2006	2005	2004
		(in millions)	
Pretax leveraged lease income	**$ 49**	$ 51	$ 53
Income tax expense	**(17)**	(18)	(19)
Net leveraged lease income	**$ 32**	$ 33	$ 34

See Note 3 under "Income Tax Matters" for additional information regarding the leveraged lease transactions.

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 average costs of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Prior to January 1, 2006, Southern Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that are outstanding as of January 1, 2006, for which the requisite service had not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

For Southern Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings from continuing operations before income taxes and net income of $28 million and $17 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $10 million.

The adoption of SFAS No. 123(R) has also resulted in a reduction in basic and diluted earnings per share from continuing operations of $0.02 and $0.03, respectively, for the year ended December 31, 2006.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact of fair-value accounting for options granted on earnings from continuing operations and basic and diluted earnings per share from continuing operations is as follows:

	As Reported	Options Impact After Tax	Pro Forma
2005			
Net income (in millions)	$1,591	$(17)	$1,574
Earnings per share *(dollars)*:			
Basic	$2.14		$2.12
Diluted	$2.13		$2.10
2004			
Net income (in millions)	$1,529	$(16)	$1,513
Earnings per share *(dollars)*:			
Basic	$2.07		$2.05
Diluted	$2.06		$2.04

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of the Company's stock over a period equal to the expected term. Southern Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	2006	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

Southern Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other") and are measured at fair value. Substantially all of Southern Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts, including derivatives related to synthetic fuel investments, are marked to market through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2006	**$13,824**	**$13,702**
2005	13,623	13,633

The fair values were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in additional minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Southern Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information. However, Southern Company and the traditional operating companies are not considered the primary beneficiaries of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts in the balance sheets.

In addition, Southern Company holds an 85 percent limited partnership investment in an energy/technology venture capital fund that is consolidated in the financial statements. During the third quarter of 2004, Southern Company terminated new investments in this fund; however, additional contributions to existing investments will still occur. Southern Company has committed to a maximum investment of $46 million, of which $43 million has been funded. Southern Company's investment in the fund at December 31, 2006 totaled $25.6 million.

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $41 million.

On December 31, 2006, Southern Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, Southern Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to each of its underfunded non-qualified pension plans, Southern Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

With the adoption of SFAS No. 158, Southern Company was required to recognize on its balance sheet previously unrecognized assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, Southern Company recorded an additional prepaid pension asset of $520 million with respect to its overfunded defined benefit plan and additional liabilities of $45 million and $553 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. The incremental effect of applying SFAS No. 158 on individual line items in the consolidated balance sheet at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension costs	$ 1,029	$ 520	$ 1,549
Other regulatory assets	239	697	936
Other property and investments	2,523	(30)	2,493
Total assets	41,671	1,187	42,858
Accumulated deferred income taxes	(5,959)	(30)	(5,989)
Other regulatory liabilities	(287)	(507)	(794)
Employee benefit obligations	(969)	(598)	(1,567)
Total liabilities	(29,608)	(1,135)	(30,743)
Accumulated other comprehensive income	109	(52)	57
Total stockholders' equity	(12,063)	(52)	(12,115)

Because the recovery of postretirement benefit expense through rates is considered probable, Southern Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71 with respect to the prepaid assets and the liabilities associated with the Company's traditional operating companies. With respect to its unregulated subsidiaries, Southern Company recorded the resulting offset as a component of accumulated other comprehensive income, net of tax.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, Southern Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The total accumulated benefit obligation for the pension plans was $5.1 billion in 2006 and $5.2 billion in 2005. Changes during the year in the projected benefit obligations and fair value of plan assets were as follows:

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$5,557**	$5,075
Service cost	**153**	138
Interest cost	**300**	286
Benefits paid	**(230)**	(214)
Plan amendments	**8**	32
Actuarial (gain) loss	**(297)**	240
Balance at end of year	**5,491**	5,557
Change in plan assets		
Fair value of plan assets at beginning of year	**6,147**	5,476
Actual return on plan assets	**759**	866
Employer contributions	**17**	19
Benefits paid	**(230)**	(214)
Fair value of plan assets at end of year	**6,693**	6,147
Funded status at end of year	**1,202**	590
Unrecognized transition amount	**-**	(6)
Unrecognized prior service cost	**-**	293
Unrecognized net gain	**-**	(2)
Fourth quarter contributions	**5**	5
Prepaid pension asset, net	**$1,207**	$ 880

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $5.1 billion and $0.3 billion, respectively. All plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the

Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	**38%**	40%
International equity	24	**23**	24
Fixed income	15	**16**	17
Real estate	15	**16**	13
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the consolidated balance sheets related to the Company's pension plans consist of the following:

	2006	2005
	(in millions)	
Prepaid pension costs	**$1,549**	$1,022
Other regulatory assets	**158**	-
Current liabilities, other	**(18)**	-
Other regulatory liabilities	**(507)**	-
Employee benefit obligations	**(324)**	(310)
Other property and investments	**-**	43
Accumulated other comprehensive income	**-**	125

Presented below are the amounts included in accumulated other comprehensive income, regulatory assets, and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year:

	Prior Service Cost	Net (Gain)/ Loss
Balance at December 31, 2006:	(in millions)	
Accumulated other comprehensive income	$ 11	$ (11)
Regulatory assets	27	131
Regulatory liabilities	225	(732)
Total	$263	$(612)
Estimated amortization in net periodic pension cost in 2007:		
Accumulated other comprehensive income	$ 1	$ 1
Regulatory assets	4	10
Regulatory liabilities	27	-
Total	$32	$11

Components of net periodic pension cost (income) were as follows:

	2006	2005	2004
		(in millions)	
Service cost	**$ 153**	$ 138	$ 128
Interest cost	**300**	286	269
Expected return on plan assets	**(456)**	(456)	(452)
Recognized net (gain) loss	**16**	10	(7)
Net amortization	**26**	24	18
Net periodic pension cost (income)	**$ 39**	$ 2	$ (44)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	(in millions)
2007	$ 241
2008	252
2009	263
2010	277
2011	294
2012 to 2016	1,786

Other Postretirement Benefits

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

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,826**	$ 1,712
Service cost	**30**	28
Interest cost	**98**	96
Benefits paid	**(79)**	(78)
Actuarial (gain) loss	**(49)**	68
Retiree drug subsidy	**4**	-
Balance at end of year	**1,830**	1,826
Change in plan assets		
Fair value of plan assets at beginning of year	**684**	592
Actual return on plan assets	**68**	78
Employer contributions	**97**	92
Benefits paid	**(118)**	(78)
Fair value of plan assets at end of year	**731**	684
Funded status at end of year	**(1,099)**	(1,142)
Unrecognized transition amount	**-**	114
Unrecognized prior service cost	**-**	121
Unrecognized net loss	**-**	428
Fourth quarter contributions	**53**	40
Accrued liability (recognized in the balance sheet)	**$(1,046)**	$ (439)

Other postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	42%	**44%**	46%
International equity	19	**20**	18
Fixed income	29	**27**	29
Real estate	6	**6**	5
Private equity	4	**3**	2
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2006	2005
	(in millions)	
Other regulatory assets	**$ 538**	$ -
Current liabilities, other	**(3)**	-
Employee benefit obligations	**(1,043)**	(439)
Accumulated other comprehensive income	**14**	-

Presented below are the amounts included in accumulated other comprehensive income and regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2006:			
Accumulated other comprehensive income	$ 4	$ 10	$ -
Regulatory assets	108	332	99
Total	$112	$342	$99
Estimated amortization as net periodic postretirement benefit cost in 2007:			
Accumulated other comprehensive income	$ -	$ -	$ -
Regulatory assets	9	14	15
Total	$ 9	$ 14	$15

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

	2006	2005	2004
	(in millions)		
Service cost	$ 30	$ 28	$ 28
Interest cost	98	97	93
Expected return on plan assets	(49)	(45)	(50)
Net amortization	43	38	35
Net postretirement cost	$122	$118	$106

In the third quarter 2004, Southern Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2), related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced Southern Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $11 million, $26 million, and $39 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2007	$ 82	$ (6)	$ 76
2008	91	(7)	84
2009	99	(9)	90
2010	107	(10)	97
2011	115	(11)	104
2012 to 2016	667	(81)	586

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$138	$118
Service and interest costs	9	8

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $62 million, $58 million, and $56 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, Southern Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Southern Company's financial statements.

Mirant Matters

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and selected other countries. It was a wholly-owned subsidiary of Southern Company until its initial public offering in October 2000. In April 2001, Southern Company completed a spin-off to its shareholders of its remaining ownership, and Mirant became an independent corporate entity.

Mirant Bankruptcy

In July 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of Texas. The Bankruptcy Court entered an order confirming Mirant's plan of reorganization on December 9, 2005, and Mirant announced that this plan became effective on January 3, 2006. As part of the plan, Mirant transferred substantially all of its assets and its restructured debt to a new corporation that adopted the name Mirant Corporation (Reorganized Mirant).

Southern Company has certain contingent liabilities associated with guarantees of contractual commitments made by Mirant's subsidiaries discussed in Note 7 under "Guarantees" and with various lawsuits related to Mirant discussed below. Southern Company has paid approximately $1.4 million in connection with the guarantees. Also, Southern Company has joint and several liability with Mirant regarding the joint consolidated federal income tax returns through 2001, as discussed in Note 5. In December 2004, as a result of concluding an IRS audit for the tax years 2000 and 2001, Southern Company paid $39 million in additional tax and interest for issues related to Mirant tax items. Based on management's assessment of the collectibility of the $39 million receivable, Southern Company has reserved approximately $13.7 million. In December 2006, Southern Company received approximately $23 million in tax refunds from the IRS related to Mirant tax items. Additional refunds are expected. The amount of any unsecured claim ultimately allowed with respect to Mirant tax items is expected to be reduced dollar-for-dollar by the amount of all refunds received from the IRS by Southern Company.

Under the terms of the separation agreements entered into in connection with the spin-off, Mirant agreed to indemnify Southern Company for costs associated with these guarantees, lawsuits, and additional IRS assessments. However, as a result of Mirant's bankruptcy, Southern Company sought reimbursement as an unsecured creditor in Mirant's Chapter 11 proceeding. As part of a complaint filed against Southern Company in June 2005 and amended thereafter, Mirant and The Official Committee of Unsecured Creditors of Mirant Corporation (Unsecured Creditors' Committee) objected to and sought equitable subordination of Southern Company's claims, and Mirant moved to reject the separation agreements entered into in connection with the spin-off. MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant, has been substituted as plaintiff in the complaint. If Southern Company's claims for indemnification with respect to these, or any additional future payments, are allowed, then Mirant's indemnity obligations to Southern Company would constitute unsecured claims against Mirant entitled to stock in Reorganized Mirant. The final outcome of this matter cannot now be determined.

MC Asset Recovery Litigation

In June 2005, Mirant, as a debtor in possession, and the Unsecured Creditors' Committee filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006, and May 2006. The third amended complaint (the complaint) alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company prior to the spin-off. The alleged fraudulent transfers and illegal dividends include without limitation: (1) certain dividends from Mirant to Southern Company in the aggregate amount of $668 million, (2) the repayment of certain intercompany loans and accrued interest in an aggregate amount of $1.035 billion, and (3) the dividend distribution of one share of Series B Preferred Stock and its subsequent redemption in exchange for Mirant's 80 percent interest in a holding company that owned SE Finance Capital Corporation and Southern Company Capital Funding, Inc., which transfer plaintiff asserts is valued at over $200 million. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability under an alter ego theory of recovery and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach its fiduciary duties to creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under the theories of restitution and unjust enrichment. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in June 2006.

On December 29, 2005, the Bankruptcy Court entered an order authorizing the transfer of this proceeding, along with certain other actions, to MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant. Under that order, Reorganized Mirant is obligated to fund up to $20 million in professional fees in connection with the lawsuits, as well as certain additional amounts. Any net recoveries from these lawsuits will be distributed to and shared equally by certain unsecured creditors and the original equity holders. In January 2006, the U.S. District Court for the Northern District of Texas substituted MC Asset Recovery as plaintiff.

On January 10, 2006, the U.S. District Court for the Northern District of Texas granted Southern Company's motion to withdraw this action from the Bankruptcy Court and, on February 15, 2006, granted Southern Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia. On May 19, 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts of the complaint. On December 11, 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims are barred; all other claims in the complaint may proceed. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. However, the final outcome of this matter cannot now be determined.

Mirant Securities Litigation

In November 2002, Southern Company, certain former and current senior officers of Southern Company, and 12 underwriters of Mirant's initial public offering were added as defendants in a class action lawsuit that several Mirant shareholders originally filed against Mirant and certain Mirant officers in May 2002. Several other similar lawsuits filed subsequently were consolidated into this litigation in the U.S. District Court for the Northern District of Georgia. The amended complaint is based on allegations related to alleged improper energy trading and marketing activities involving the California energy market, alleged false statements and omissions in Mirant's prospectus for its initial public offering and in subsequent public statements by Mirant, and accounting-related issues previously disclosed by Mirant. The lawsuit purports to include persons who acquired Mirant securities between September 26, 2000 and September 5, 2002.

In July 2003, the court dismissed all claims based on Mirant's alleged improper energy trading and marketing activities involving the California energy market. The remaining claims do not allege any improper trading and marketing activity, accounting errors, or material misstatements or omissions on the part of Southern Company but seek to impose liability on Southern Company based on allegations that Southern Company was a "control person" as to Mirant prior to the spin-off date. Southern Company filed an answer to the consolidated amended class action complaint in September 2003. Plaintiffs have also filed a motion for class certification.

During Mirant's Chapter 11 proceeding, the securities litigation was stayed, with the exception of limited discovery. Since Mirant's plan of reorganization has become effective, the stay has been lifted. On March 24, 2006, the plaintiffs filed a motion for reconsideration requesting that the court vacate that portion of its July 14, 2003 order dismissing the plaintiffs' claims based upon Mirant's alleged improper energy trading and marketing activities involving the California energy market. Southern Company and the other defendants have opposed the plaintiffs' motion. The plaintiffs have also stated that they intend to request that the court grant leave for them to amend the complaint to add allegations based upon claims asserted against Southern Company in the MC Asset Recovery litigation.

Under certain circumstances, Southern Company will be obligated under its Bylaws to indemnify the four current and/or former Southern Company officers who served as directors of Mirant at the time of its initial public offering through the date of the spin-off and who are also named as defendants in this lawsuit. The final outcome of this matter cannot now be determined.

Southern Company Employee Savings Plan Litigation

In June 2004, an employee of a Southern Company subsidiary filed a complaint, which was amended in December 2004 and November 2005 in the U.S. District Court for the Northern District of Georgia on behalf of a purported class of participants in or beneficiaries of The Southern Company Employee Savings Plan (Plan) at any time since April 2, 2001 and whose Plan accounts included investments in Mirant common stock. The complaint asserts claims under ERISA against defendants Southern Company, SCS, the Employee Savings Plan Committee, the Pension Fund Investment Review Committee, individual members of such committees, and the SCS Board of Directors during the putative class period. The plaintiff alleges that the various defendants had certain fiduciary duties under ERISA regarding the Mirant shares distributed to Southern Company shareholders in the spin-off and held in the Mirant Stock Fund in the Plan. The plaintiff alleges that the various defendants breached purported fiduciary duties by, among other things, failing to adequately determine whether Mirant stock was appropriate to hold in the Plan and failing to adequately inform Plan participants that Mirant stock was not an appropriate investment for their retirement assets based on Mirant's alleged improper energy trading and accounting practices, mismanagement, and business conditions. The plaintiff also alleges that certain defendants failed to monitor Plan fiduciaries and that certain defendants had conflicting interests regarding Mirant, which prevented them from acting solely in the interests of Plan participants and beneficiaries. The plaintiff seeks class-wide equitable relief and an unspecified amount of monetary damages.

On October 4, 2005, the court dismissed the plaintiff's claims for certain types of equitable relief, but allowed the remainder of the ERISA claims to proceed. The defendants filed answers to the second amended complaint in January 2006 and filed motions for summary judgment and to stay discovery in February 2006. In April 2006, the U.S. District Court for the Northern District of Georgia granted summary judgment in favor of Southern Company and all other defendants in the case. The plaintiff filed an appeal of the ruling. On December 19, 2006, the parties executed a written settlement term sheet, to be followed by a formal settlement agreement. On the same day, the parties waived oral argument in the U.S. Court of Appeals for the Eleventh Circuit, where the case was pending, and moved to remand the matter to the district court. The motion was granted on December 20, 2006.

The settlement term sheet admits no liability and provides for a payment of $15 million, to be made by the Company's insurance carrier, to the Plan, after deduction of any award for plaintiff's attorneys fees and certain other expenses if approved by the district court. Because the case is a putative class action, the settlement requires court approval. The district court will consider all matters related to the settlement. Pending the settlement approval, the ultimate outcome of this matter cannot now be determined.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene

County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit, and on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

Southern Company believes that the traditional operating companies complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in any one of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against Georgia Power for alleged violations of the Clean Air Act at four of the units at Plant Wansley. The civil action requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for Georgia Power on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

Environmental Remediation

Georgia Power has been designated as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act. In 1995, the EPA designated Georgia Power and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia, that is listed on the federal National Priorities List. As of December 31, 2006, Georgia Power had recorded approximately $6 million in cumulative expenses associated with its agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. Georgia Power has also recognized $36 million in cumulative expenses through December 31, 2006 for the assessment and anticipated cleanup of other sites on the Georgia Hazardous Sites Inventory.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

FERC Matters

Market-Based Rate Authority

Each of the traditional operating companies and Southern Power has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $19.7 million for the Southern Company system. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the traditional operating companies and Southern Power may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $55.4 million for the Southern Company system, of which $15.5 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

Southern Company and its subsidiaries believe that there is no meritorious basis for these proceedings and are vigorously defending themselves in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on Southern Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including Georgia Power, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of Southern Company and its subsidiaries believe that they have complied with applicable laws and that the plaintiffs' claims are without merit.

In November 2003, the Second Circuit Court in Gadsden County, Florida, ruled in favor of the plaintiffs on their motion for partial summary judgment concerning liability in one such lawsuit brought by landowners regarding the installation and use of fiber optic cable over Gulf Power rights of way located on the landowners' property. Subsequently, the plaintiffs sought to amend their complaint and asked the court to enter a final declaratory judgment and to enter an order enjoining Gulf Power from allowing expanded general telecommunications use of the fiber optic cables that are the subject of this litigation. In January 2005, the trial court granted in part the plaintiffs' motion to amend their complaint and denied the requested declaratory and injunctive relief. In November 2005, the trial court ruled in favor of the plaintiffs and against Gulf Power on their respective motions for partial summary judgment. In that same order, the trial court also denied Gulf Power's motion to dismiss certain claims. The court's ruling allowed for an immediate appeal to the Florida First District Court of Appeal, which Gulf Power filed in December 2005. On October 26, 2006, the Florida First District Court of Appeal issued an order dismissing Gulf Power's December 2005 appeal on the basis that the trial court's order was a non-final order and therefore not subject to review on appeal at this time. The case is once again pending in the trial court for further proceedings. The final outcome of this matter cannot now be determined. In the event of an adverse verdict in this case, Gulf Power could appeal the issues of both liability and damages or other relief granted.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in another such lawsuit brought by landowners against Georgia Power based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The court also dismissed Southern Telecom from this case. Georgia Power appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the trial court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which was denied. On October 10, 2006, the Superior Court of Decatur County, Georgia granted Georgia Power's motion for summary judgment. The period during which the plaintiff could have appealed has expired. This matter is now concluded.

To date, Mississippi Power has entered into agreements with plaintiffs in approximately 90 percent of the actions pending against Mississippi Power to clarify its easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and dismissals of the related cases are in progress. These agreements have not resulted in any material effects on Mississippi Power's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Income Tax Matters

Southern Company undergoes audits by the IRS for each of its tax years. The IRS has completed its audits of

Southern Company's consolidated federal income tax returns for all years through 2003. Southern Company participates in four international leveraged lease transactions and receives federal income tax deductions for depreciation and amortization, as well as interest on related debt. The IRS proposed to disallow the tax losses for one of these leases (a lease-in-lease-out, or LILO) in connection with its audit of 1997 through 2001. In October 2004, Southern Company submitted the issue to the IRS appeals division and in February 2005 reached a negotiated settlement with the IRS which is now final.

In connection with its audits of tax years 2000 – 2001 and 2002 – 2003 the IRS also challenged Southern Company's deductions related to three other international lease (sale-in-lease-out, or SILO) transactions. In the third quarter 2006, Southern Company paid the full amount of the disputed tax and the applicable interest on the SILO issue for tax years 2000 – 2001 and filed a claim for refund which has now been denied by the IRS. The disputed tax amount is $79 million and the related interest is approximately $24 million for these tax years. This payment, and the subsequent IRS disallowance of the refund claim, closed the issue with the IRS and Southern Company plans to proceed with litigation. The IRS has also raised the SILO issues for tax years 2002 and 2003. The estimated amount of disputed tax and interest for these years is approximately $83 million and $15 million, respectively. The tax and interest for these tax years was paid to the IRS in the fourth quarter 2006. Southern Company has accounted for both payments in 2006 as deposits, as management believes no additional tax or interest liabilities have been incurred. For tax years 2000 through 2006, Southern Company has claimed $284 million in tax benefits related to these SILO transactions challenged by the IRS. The ultimate outcome of this matter cannot now be determined. See Note 1 under "Leveraged Leases" for additional information.

Alabama Power Retail Regulatory Matters

Alabama Power operates under a Rate Stabilization and Equalization Plan (Rate RSE) approved by the Alabama PSC. Rate RSE provides for periodic annual adjustments based upon Alabama Power's earned return on end-of-period retail common equity; however, in October 2005, Alabama Power and the Alabama PSC agreed to a moratorium on any rate increase under Rate RSE until January 2007. In October 2005, the Alabama PSC approved a revision to Rate RSE requested by Alabama Power. Effective January 2007, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4 percent per year and any annual adjustment is limited to 5 percent. Rates remain unchanged when the projected return on common equity (ROE) ranges between 13 percent and 14.5 percent. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range. Alabama Power made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007 is 4.76 percent, or $193 million annually, and was effective in January 2007. The ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the placing of new generating facilities in retail service and for the recovery of retail costs associated with certificated purchased power agreements (Rate CNP). An increase of 0.8 percent in retail rates, or $25 million annually, was effective July 2004 under Rate CNP for new certificated power purchase agreements. In April 2005, an adjustment to Rate CNP decreased retail rates by approximately 0.5 percent, or $19 million annually. The annual true-up adjustment effective in April 2006 increased retail rates by 0.5 percent, or $19 million annually. The request filed in February 2007 did not require any adjustment beginning in April 2007.

In October 2004, the Alabama PSC approved a request by Alabama Power to amend Rate CNP to also provide for the recovery of retail costs associated with environmental laws and regulations, effective in January 2005. The rate mechanism began operation in January 2005 and provides for the recovery of these costs pursuant to a factor that will be calculated annually. Environmental costs to be recovered include operation and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased approximately 1.0 percent in January 2005, 1.2 percent in January 2006, and 0.6 percent in January 2007.

Alabama Power fuel costs are recovered under Rate ECR (Energy Cost Recovery), which provides for the addition of a fuel and energy cost factor to base rates. In December 2005, the Alabama PSC approved an increase that allows for the recovery of approximately $227 million in existing under recovered fuel costs over a two-year period. Based on the order, a portion of the under recovered regulatory clause revenues was reclassified from current assets to deferred charges and other assets in the balance sheet.

Georgia Power Retail Regulatory Matters

In December 2004, the Georgia PSC approved a three-year retail rate plan ending December 31, 2007 (2004 Retail Rate Plan) for Georgia Power. Under the terms of the 2004 Retail Rate Plan, Georgia Power's earnings are evaluated against a retail ROE range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by Georgia Power. Retail rates and customer fees were increased by approximately $203 million effective January 1, 2005. In 2007, Georgia Power will refund 2005 retail earnings in excess of a 12.25 percent retail ROE. The refund amount is not expected to be material. No refund is anticipated for 2006. Georgia Power is required to file a general rate case by July 1, 2007 in response to which the Georgia PSC would be expected to determine whether the rate order should be continued, modified, or discontinued.

In December 2001, the Georgia PSC approved a three-year retail rate plan (2001 Retail Rate Plan) for Georgia Power ending December 31, 2004. Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail return on common equity range of 10 percent to 12.95 percent. Georgia Power's earnings in all three years were within the common equity range. Under the 2001 Retail Rate Plan, Georgia Power amortized a regulatory liability of $333 million, related to previously recorded accelerated amortization expenses, equally over three years beginning in 2002. Also, the 2001 Retail Rate Plan required Georgia Power to recognize capacity and operating and maintenance costs related to certified purchase power contracts evenly into rates over a three-year period ended December 31, 2004.

In May 2005, the Georgia PSC approved Georgia Power's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005. The Georgia PSC's order instructed that under recovered fuel amounts be reviewed semi-annually beginning February 2006. If the amount under or over recovered exceeded $50 million at any evaluation date, Georgia Power was required to file for a temporary fuel rate change. Under recovered fuel amounts for the period subsequent to June 1, 2005 totaled $327.5 million through December 31, 2005. In addition, in accordance with a separate Georgia PSC order, Savannah Electric was scheduled to file an additional request for a fuel cost recovery increase in January 2006. In connection with the merger of Georgia Power and Savannah Electric, Georgia Power agreed with a Georgia PSC staff recommendation to forego the temporary fuel rate process, and Savannah Electric postponed its scheduled filing. Instead, Georgia Power and Savannah Electric filed a combined request in March 2006 to increase the fuel cost recovery rate.

On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in Georgia Power's total annual fuel billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required Georgia Power to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, Georgia Power filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate.

On November 13, 2006, under an agreement with the Georgia PSC staff, Georgia Power filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs. On February 6, 2007, the Georgia PSC ruled on the request and approved an increase in Georgia Power's total annual billings of approximately $383 million. The Georgia PSC order reduced Georgia Power's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires Georgia Power to file for a new fuel cost recovery rate no later than March 1, 2008. The new rates will become effective on March 1, 2007. Estimated under recovered fuel costs are to be recovered through May 2009 for customers in the former Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, Georgia Power had an under recovered fuel balance of approximately $898 million.

Storm Damage Cost Recovery

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution facilities and the cost of uninsured damages to its generation facilities and other property. Following Hurricanes Ivan, Dennis, and Katrina in September 2004, July 2005, and August 2005, respectively, each of the affected traditional operating companies has been authorized by its respective state PSC to defer the portion of the storm restoration costs incurred that exceeded the balance in its storm damage reserve account. As of December 31, 2006, the under recovered balance in Southern Company's storm damage reserve accounts totaled approximately $89 million, of which approximately $57 million and $32 million, respectively, is included in the balance sheets herein under "Other Current Assets" and "Other Regulatory Assets." Approximately $63 million of the under recovered balances are being recovered through separate surcharges or rate riders approved by the Florida and Alabama PSCs, as discussed further below. The recovery of the remaining deferred costs is subject to the approval of the respective state PSC.

In June 2006, the Mississippi PSC issued an order based upon a stipulation between Mississippi Power and the Mississippi Public Utilities Staff. The stipulation and the associated order certified actual storm restoration costs relating to Hurricane Katrina through April 30, 2006 of $267.9 million and affirmed estimated additional costs through December 31, 2007 of $34.5 million, for total storm restoration costs of $302.4 million which was net of insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million. Of the total amount, $292.8 million applies to Mississippi Power's retail jurisdiction. The order directed Mississippi Power to file an application with the Mississippi Development Authority (MDA) for a Community Development Block Grant (CDBG). Mississippi Power filed the CDBG application with the MDA in September 2006. On October 30, 2006, Mississippi Power received from the MDA a CDBG in the amount of $276.4 million. Mississippi Power has appropriately allocated and applied these CDBG proceeds to both retail and wholesale storm restoration cost recovery.

Mississippi Power filed an application for a financing order with the Mississippi PSC on July 3, 2006 for restoration costs under the state bond program. On October 27, 2006, the Mississippi PSC issued a financing order that authorizes the issuance of $121.2 million of system restoration bonds. This amount includes $25.2 million for the retail storm recovery costs not covered by the CDBG, $60 million for a property damage reserve, and $36 million for the retail portion of the construction of the storm operations facility. The bonds will be issued by the Mississippi Development Bank on behalf of the State of Mississippi and will be reported as liabilities by the State of Mississippi. Periodic true-up mechanisms will be structured to comply with terms and requirements of the legislation. Details regarding the issuance of the bonds have not been finalized. The final outcome of this matter cannot now be determined.

As of December 31, 2006, Mississippi Power's under recovered balance in the property damage reserve account totaled approximately $4.7 million which is included in the balance sheets herein under "Current Assets."

In July 2006, the Florida PSC issued its order approving a stipulation and settlement between Gulf Power and several consumer groups that resolved all matters relating to Gulf Power's request for recovery of incurred costs for storm-recovery activities and the replenishment of Gulf Power's property damage reserve. The order provides for an extension of the storm-recovery surcharge currently being collected by Gulf Power for an additional 27 months, expiring in June 2009. According to the stipulation, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by Gulf Power through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve. The annual accrual to the reserve of $3.5 million and Gulf Power's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. Gulf Power made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of the March 2005 agreement regarding Hurricane Ivan costs that established the existing surcharge, Gulf Power agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the stipulation do not alter or affect that portion of the prior agreement. According to the order, in the case of future storms, if Gulf Power incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, Gulf Power will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. Gulf Power would then petition the Florida PSC for full recovery through an additional surcharge or other cost recovery mechanism.

As of December 31, 2006, Gulf Power's unrecovered balance in the property damage reserve totaled approximately $45.7 million, of which approximately $28.8 million and $16.9 million, respectively, are included in the balance sheets herein under "Current Assets" and "Deferred Charges and Other Assets."

At Alabama Power, operation and maintenance expenses associated with Hurricane Ivan were $57.8 million. In 2005, Alabama Power received Alabama PSC approvals to return certain regulatory liabilities to the retail customers. These orders also allowed Alabama Power to simultaneously recover from customers accruals of approximately $48 million primarily to offset the costs of Hurricane Ivan and restore a positive balance in the natural disaster reserve. The combined effect of these orders had no impact on net income in 2005.

In December 2005, the Alabama PSC approved a separate rate rider to recover Alabama Power's $51 million of deferred Hurricane Dennis and Katrina operation and maintenance costs over a two-year period and to replenish its reserve to a target balance of $75 million over a five-year period.

As of December 31, 2006, Alabama Power had recovered $49.5 million of the costs allowed for storm-recovery activities, of which $34.5 million was a reduction in the deficit balance in the property damage reserve account related to costs deferred from previous storms. The remaining under recovered balance in the property damage reserve account totaled approximately $16.8 million at December 31, 2006 and is included in the balance sheets herein under "Current Assets." The remaining $15.0 million of the recovered amount was used to establish the target reserve for future storms. The balance in the target reserve for future storms was $13.2 million at December 31, 2006, and is included in the balance sheets herein under "Other Regulatory Liabilities."

Southern Company Gas Sale

On January 4, 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary, including natural gas inventory, accounts receivable, and customer list, to Gas South, LLC, an affiliate of Cobb Electric Membership Corporation. Southern Company Gas' sale of such assets was pursuant to a Purchase and Sale Agreement dated November 18, 2005 between Southern Company Gas and Gas South. The gross proceeds from the sale were approximately $126 million. This sale had no material impact on Southern Company's net income. As a result of the sale, Southern Company's financial statements and related information reflect Southern Company Gas as discontinued operations for all periods presented.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in units 1 and 2 of Plant Miller and related facilities jointly with Alabama Electric Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia, the city of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2006, Alabama Power's, Georgia Power's, and Southern Power's ownership and investment (exclusive of nuclear fuel) in jointly owned facilities with the above entities were as follows:

	Percent Ownership	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,289	$1,857
Plant Hatch (nuclear)	50.1	925	502
Plant Miller (coal) Units 1 and 2	91.8	958	396
Plant Scherer (coal) Units 1 and 2	8.4	116	60
Plant Wansley (coal)	53.5	396	179
Rocky Mountain (pumped storage)	25.4	170	95
Intercession City (combustion turbine)	33.3	12	2
Plant Stanton (combined cycle) Unit A	65.0	155	13

At December 31, 2006, the portion of total construction work in progress related to Plants Miller, Scherer, and Wansley was $14.9 million, $1.7 million, and $53.1 million, respectively, primarily for environmental projects.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

Mirant was included in the consolidated federal tax return through April 2, 2001. In December 2004, the IRS concluded its audit for the tax years 2000 and 2001, and Southern Company paid $39 million in additional tax and interest for issues related to Mirant tax items. Under the terms of the separation agreements, Mirant agreed to indemnify Southern Company for subsequent assessment of any additional taxes related to its transactions prior to the spin off. However, as a result of Mirant's bankruptcy, Southern Company sought reimbursement as an unsecured creditor. Based on management's assessment of the collectibility of this $39 million receivable, Southern Company has reserved approximately $13.7 million. In December 2006, Southern Company received approximately $23 million in tax refunds from the IRS related to Mirant tax items. For additional information, see Note 3 under "Mirant Matters – Mirant Bankruptcy."

At December 31, 2006, the tax-related regulatory assets and liabilities were $896 million and $293 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 the current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2006	2005	2004
		(in millions)	
Total provision for income taxes:			
Federal –			
Current	$466	$ 61	$ 14
Deferred	207	419	482
	673	480	496
State –			
Current	110	35	15
Deferred	(2)	80	76
	108	115	91
Total	$781	$595	$587

Net cash payments for income taxes in 2006, 2005, and 2004 were $649 million, $100 million, and $78 million, respectively.

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:

	2006	2005
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$4,675**	$4,613
Property basis differences	**962**	994
Leveraged lease basis differences	**625**	519
Employee benefit obligations	**530**	333
Under recovered fuel clause	**543**	528
Premium on reacquired debt	**120**	126
Regulatory assets associated with employee benefit obligations	**362**	-
Regulatory assets associated with asset retirement obligations	**453**	444
Storm reserve	**33**	68
Other	**126**	156
Total	**8,429**	7,781
Deferred tax assets:		
Federal effect of state deferred taxes	**267**	263
State effect of federal deferred taxes	**63**	88
Employee benefit obligations	**615**	210
Other property basis differences	**156**	148
Deferred costs	**131**	126
Unbilled revenue	**76**	58
Other comprehensive losses	**60**	96
Alternative minimum tax carryforward	**-**	202
Regulatory liabilities associated with employee benefit obligations	**196**	-
Asset retirement obligations	**453**	444
Other	**272**	247
Total	**2,289**	1,882
Total deferred tax liabilities, net	**6,140**	5,899
Portion included in prepaid expenses (accrued income taxes), net	**(175)**	(180)
Deferred state tax assets	**24**	17
Accumulated deferred income taxes in the balance sheets	**$5,989**	$5,736

The alternative minimum tax credits do not expire.

At December 31, 2006, Southern Company also had available State of Georgia net operating loss carryforward deductions totaling $1.0 billion, which could result in net state income tax benefits of $59 million, if utilized. These deductions will expire between 2007 and 2021. During 2006, Southern Company utilized $10 million in available net operating losses, which resulted in a $0.6 million state income tax benefit. Beginning in 2002, the State of Georgia allowed the filing of a combined return, which should substantially reduce any additional net operating loss carryforwards.

In September 2006, Georgia Power filed its 2005 income tax returns, which included certain state income tax credits that resulted in a lower effective income tax rate for the year ended December 31, 2006 when compared to 2005. Georgia Power has also filed similar claims for the years 2001 through 2004. Amounts recorded in Southern Company's financial statements for the year ended December 31, 2006 related to these claims are not material. The Georgia Department of Revenue is currently reviewing these claims. If approved as filed, such claims could have a significant, and possibly material, effect on Southern Company's net income. The ultimate outcome of this matter cannot now be determined.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $23 million in 2006, $25 million in 2005, and $27 million in 2004. At December 31, 2006, all investment tax credits available to reduce federal income taxes payable had been utilized.

The provision for income taxes differs from the amount of income taxes determined by applying the applicable U.S. federal statutory rate to earnings before income taxes and preferred dividends of subsidiaries, as a result of the following:

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.9**	3.4	2.8
Synthetic fuel tax credits	**(2.7)**	(8.0)	(8.5)
Employee stock plans dividend deduction	**(1.4)**	(1.5)	(1.5)
Non-deductible book depreciation	**1.0**	1.1	1.1
Difference in prior years' deferred and current tax rate	**(0.3)**	(1.8)	(0.7)
Other	**(1.8)**	(1.4)	(0.9)
Effective income tax rate	**32.7%**	26.8%	27.3%

6. FINANCING

Mandatorily Redeemable Preferred Securities/ Long-Term Debt Payable to Affiliated Trusts

Southern Company and the traditional operating companies have each formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Southern Company or the applicable traditional operating company through the issuance of junior subordinated notes totaling $1.6 billion, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trusts (including Securities Due Within One Year). Southern Company and the traditional operating companies each consider that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2006, preferred securities of $1.5 billion were outstanding. Southern Company guarantees $206 million of notes related to these securities issued on its behalf. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 is as follows:

	2006	2005
	(in millions)	
Capitalized leases	$ 13	$ 13
First mortgage bonds	-	45
Pollution control bonds	-	12
Senior notes	1,369	697
Long-term debt payable to affiliated trusts	-	72
Other long-term debt	36	47
Preferred stock	-	15
Total	$1,418	$901

Debt and preferred stock redemptions, and/or serial maturities through 2011 applicable to total long-term debt are as follows: $1.4 billion in 2007; $499 million in 2008; $604 million in 2009; $286 million in 2010, and $329 million in 2011. On February 1, 2007, $400 million of the 2007 long-term debt principal amount matured. The maturity was funded with short-term borrowings.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. At January 1, 2006, Alabama Power and Gulf Power had mortgages that secured first mortgage bonds they had issued and constituted a direct first lien on substantially all of their respective fixed property and franchises. Alabama Power discharged its remaining outstanding first mortgage bond obligations and the first mortgage lien was removed in May 2006. Following the maturity of Gulf Power's remaining outstanding first mortgage bonds in November 2006, the first mortgage lien was removed on January 26, 2007. The Mississippi Power and Georgia Power first mortgage liens were removed in 2005 and 2002, respectively. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain pollution control bonds with an outstanding principal amount of $194 million. There are no agreements or other arrangements among the subsidiary companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At the beginning of 2007, unused credit arrangements with banks totaled $3.35 billion, of which $656 million expires during 2007 and $2.7 billion expires in 2008 and beyond. Of the $2.7 billion expiring in 2008 and beyond, $2.4 billion does not expire until 2011. The following table outlines the credit arrangements by company:

			Expires	
Company	Total	Unused	2007	2008 & beyond
	(in millions)			
Alabama Power	$ 965	$ 965	$365	$ 600
Georgia Power	910	904	40	870
Gulf Power	120	120	120	-
Mississippi Power	181	181	101	80
Southern Company	750	750	-	750
Southern Power	400	400	-	400
Other	30	30	30	-
Total	$3,356	$3,350	$656	$2,700

Approximately $79 million of the credit facilities expiring in 2007 allow the execution of term loans for an additional two-year period, and $343 million allow execution of one-year term loans. Most of these agreements include stated borrowing rates.

All of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees are one-eighth of 1 percent or less for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Most of the credit arrangements with banks have covenants that limit debt levels to 65 percent of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts. At December 31, 2006, Southern Company, Southern Power, and the traditional operating companies were each in compliance with their respective debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company and its subsidiaries are currently in compliance with all such covenants. In the event of a material adverse change, as defined in Gulf Power's credit agreements, Gulf Power would be prohibited from borrowing against unused credit arrangements totaling $10 million.

A portion of the $3.35 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control bonds. The amount of variable rate pollution control bonds requiring liquidity support as of December 31, 2006 was $719 million.

Southern Company, the traditional operating companies, and Southern Power borrow primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company and the traditional operating companies may also borrow through various other arrangements with banks and extendible commercial note programs. The amount of commercial paper outstanding and included in notes payable in the balance sheets at December 31, 2006 and December 31, 2005 was $1.8 billion and $944 million, respectively. In addition, the Company and the traditional operating companies had $30 million of extendible commercial notes and $140 million of short-term bank loans outstanding at December 31, 2006.

During 2006, the peak amount outstanding for short-term debt was $2.1 billion, and the average amount outstanding was $1.6 billion. The average annual interest rate on short-term debt was 5.2 percent for 2006 and 3.5 percent for 2005.

Financial Instruments

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts generally shift substantially all fuel cost responsibility to the purchaser. Each of the traditional operating companies has implemented fuel-hedging programs at the instruction of their respective state PSCs. Together with Southern Power, the traditional operating companies may enter into hedges of forward electricity sales.

At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts was reflected in the financial statements as follows:

	Amounts (in millions)
Regulatory assets, net	$(85)
Accumulated other comprehensive income	3
Net income	-
Total fair value	$(82)

The fair value gains or losses for hedges that are recoverable through the regulatory fuel clauses are recorded as regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. For other hedges qualifying as cash flow hedges, including those of Southern Power, the fair value gains or losses are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. For 2006, 2005, and 2004, the pre-tax gains (losses) reclassified from other comprehensive income from continuing operations to fuel expense or revenues was not material. For the year 2007, approximately $3 million of gains are expected to be reclassified from other comprehensive income to revenues. There was no significant ineffectiveness recorded in earnings for any period presented. Southern Company has energy-related hedges in place up to and including 2009.

During 2006, Southern Company entered into derivative transactions with net initial premiums paid of $20 million to reduce its exposure to a potential phase-out of certain income tax credits in 2006 and 2007. In accordance with Section 45K of the Internal Revenue Code, these tax credits are subject to limitation as the annual average price of oil increases. At December 31, 2006, the fair value of the derivatives was a $12 million net liability. For 2006 and 2005, the fair value loss recognized in other income (expense) to mark the transactions to market was $32 million and $7 million, respectively.

Southern Company and certain subsidiaries also enter into derivatives to hedge exposure to changes in interest rates. Derivatives related to fixed-rate securities are accounted for as fair value hedges. Derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings.

At December 31, 2006, Southern Company had $2.4 billion notional amount of interest rate swaps and options outstanding with net fair value losses of $2 million as follows:

Fair Value Hedges

Company	Hedge Maturity	Variable Rate Paid	Notional Amount	Fair Value (Loss)
			(in millions)	
Southern Company				
	2007	6-month LIBOR - 0.10%*	$400	$(0.1)

Cash Flow Hedges

Company	Hedge Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/ (Loss)
			(in millions)	
Alabama Power				
	2007	2.01%**	$536	$ 0.8
	2017	6.15%***	100	(1.9)
	2017	6.15%***	100	(1.9)
Georgia Power				
	2007	3.85%***	400	0.1
	2037	5.75%***	300	1.4
	2017	5.29%	225	(2.0)
	2007	2.68%	300	1.4
	2007	2.50%**	14	0.2

* London Interbank Offer Rate (LIBOR).

** Hedged using the Bond Market Association Municipal Swap Index.

*** Interest rate collar (showing only the rate cap percentage).

For fair value hedges where the hedged item is an asset, liability, or firm commitment, the changes in the fair value of the hedging derivatives are recorded in earnings and are offset by the changes in the fair value of the hedged item.

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2006, 2005, and 2004, the Company incurred net losses of $1 million, $19 million, and $7 million, respectively, upon termination of certain interest derivatives at the same time it issued debt. These losses have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative. For 2006, 2005, and 2004, approximately $1 million, $10 million, and $23 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2007, pre-tax losses of approximately $15 million are expected to be reclassified from other comprehensive income to interest expense.

7. COMMITMENTS

Construction Program

Southern Company is engaged in continuous construction programs, currently estimated to total $3.9 billion in 2007, $4.5 billion in 2008, and $4.8 billion in 2009. These amounts include $120 million, $109 million, and $122 million in 2007, 2008, and 2009, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included herein under "Fuel and Purchased Power Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; acquisition of additional generating assets; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the ongoing construction program, which includes new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards.

Long-Term Service Agreements

The traditional operating companies and Southern Power have entered into Long-Term Service Agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for the combined cycle and combustion turbine generating facilities owned by the subsidiaries, with the exception of newly acquired Plants DeSoto and Rowan. The LTSAs provide that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, except for Southern Power's Plant Dahlberg, these LTSAs are in effect through two major inspection cycles per unit. The Dahlberg agreement is in effect through the first major inspection of each unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $1.6 billion over the remaining life of the agreements, which are currently estimated to range up to 30 years. However, the LTSAs contain various cancellation provisions at the option of the purchasers.

Georgia Power has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $12.2 million. The contract contains cancellation provisions at the option of Georgia Power.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. All work performed by GE is capitalized or charged to expense (net of any joint owner billings), as appropriate based on the nature of the work.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, Southern Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006. Also, Southern Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2006 were as follows:

	Commitments			
	Natural Gas	Coal	Nuclear Fuel	Purchased Power
	(in millions)			
2007	$1,347	$ 3,294	$120	$ 173
2008	1,174	2,609	109	175
2009	728	1,720	122	199
2010	454	1,024	160	185
2011	355	620	145	166
2012 and thereafter	2,740	2,221	236	890
Total	$6,798	$11,488	$892	$1,788

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

Operating Leases

In May 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), whose partners are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50 percent of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The initial lease term ends in 2011, and the lease includes a purchase and renewal option based on the cost of the facility at the inception of the lease. Mississippi Power is required to amortize approximately 4 percent of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, Mississippi Power may elect to renew for 10 years. If the lease is renewed, the agreement calls for Mississippi Power to amortize an additional 17 percent of the initial completion cost over the renewal period. Upon termination of the lease, at Mississippi Power's option, it may either exercise its purchase option or the facility can be sold to a third party.

The lease provides for a residual value guarantee, approximately 73 percent of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the asset. A liability of approximately $9 million for the fair market value of this residual value guarantee is included in the balance sheet as of December 31, 2006.

Southern Company also has other operating lease agreements with various terms and expiration dates. Total operating lease expenses were $161 million, $150 million, and $156 million for 2006, 2005, and 2004, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. At December 31, 2006, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments			
	Plant Daniel	Barges & Rail Cars	Other	Total
	(in millions)			
2007	$ 29	$ 53	$ 53	$135
2008	29	48	43	120
2009	29	39	36	104
2010	28	30	29	87
2011	28	22	23	73
2012 and thereafter	-	62	124	186
Total	$143	$254	$308	$705

For the traditional operating companies, the barge and rail car lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2009, 2010, and 2011, and the maximum obligations are $20 million, $62 million, and $64 million, respectively. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

Prior to the spin-off, Southern Company made separate guarantees to certain counterparties regarding performance of contractual commitments by Mirant's trading and marketing subsidiaries. The total notional amount of guarantees outstanding at December 31, 2006 is less than $20 million, all of which will expire by 2009.

As discussed earlier in this Note under "Operating Leases," Alabama Power, Georgia Power, and Mississippi Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

In 2006, Southern Company raised $1 million (53,000 shares) from the issuance of new common shares and $136 million (5 million shares) from the issuance of treasury stock under the Company's various stock programs. In 2005, the Company raised $213 million (10 million shares) from the issuance of new common shares under the Company's various stock programs.

Stock Repurchased

In early January 2006, Southern Company discontinued the common stock repurchase program begun in 2005 which was designed primarily to offset the shares of common stock issued under the Company's various stock programs. In January 2006, prior to the discontinuance of the program, Southern Company repurchased approximately 3,000 shares of common stock at a total cost of $0.1 million. During 2005, Southern Company repurchased 10 million shares of common stock at a total cost of $352 million.

Shares Reserved

At December 31, 2006, a total of 88.9 million shares was reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (stock option plan).

Stock Option Plan

Southern Company provides non-qualified stock options to a large segment of its employees ranging from line management to executives. As of December 31, 2006, 6,509 current and former employees participated in the stock option plan. The maximum number of shares of common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options that were used under SFAS No. 123.

Southern Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject To Option	Weighted Average Exercise Price
Outstanding at Dec. 31, 2005	31,347,355	$27.13
Granted	6,656,788	33.81
Exercised	(3,239,698)	23.97
Cancelled	(155,202)	31.22
Outstanding at Dec. 31, 2006	34,609,243	$28.69
Exercisable at Dec. 31, 2006	22,045,449	$26.37

The number of stock options vested, and expected to vest in the future, as of December 31, 2006 is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

As of December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.4 years and 5.2 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $283 million and $231 million, respectively.

As of December 31, 2006, there was $10 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $36 million, $130 million, and $81 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $14 million, $50 million, and $31 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

Southern Company has a policy of issuing shares to satisfy share option exercises. In January 2006, the Company started reissuing treasury shares that it had previously repurchased. The repurchase program ended in January 2006. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2006, 2005, and 2004 was $77 million, $213 million, and $119 million, respectively.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to outstanding options under the stock option plan. The effect of the stock options was determined using the treasury stock method. Shares used to compute diluted earnings per share are as follows:

	Average Common Stock Shares		
	2006	2005	2004
	(in thousands)		
As reported shares	**743,146**	743,927	738,879
Effect of options	**4,739**	4,600	4,197
Diluted shares	**747,885**	748,527	743,076

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2006, consolidated retained earnings included $4.8 billion of undistributed retained earnings of the subsidiaries. Southern Power's credit facility contains potential limitations on the payment of common stock dividends; as of December 31, 2006, Southern Power was in compliance with all such requirements.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $10.76 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. A company could be assessed up to $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests, is $201 million and $203 million, respectively, per incident, but not more than an aggregate of $30 million per company to be paid for each incident in any one year.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

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

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $38 million and $49 million, respectively.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all "non-certified" terrorist acts, i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segment is the sale of electricity in the Southeast by the traditional operating companies and Southern Power. Net income and total assets for discontinued operations are included in the reconciling eliminations column. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in synthetic fuels and leveraged lease projects, telecommunications, and energy-related services. Southern Power's revenues from sales to the traditional operating companies were $492 million, $557 million, and $425 million in 2006, 2005, and 2004, respectively. In addition, see Note 1 under "Related Party Transactions" for information regarding revenues from services for synthetic fuel production that are included in the cost of fuel purchased by Alabama Power and Georgia Power. All other intersegment revenues are not material. Financial data for business segments and products and services are as follows:

Business Segment

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2006				(in millions)			
Operating revenues	**$13,920**	**$ 777**	**$(609)**	**$14,088**	**$ 413**	**$(145)**	**$14,356**
Depreciation and amortization	**1,098**	**66**	**-**	**1,164**	**37**	**(1)**	**1,200**
Interest income	**33**	**2**	**-**	**35**	**7**	**(1)**	**41**
Interest expense	**637**	**80**	**-**	**717**	**149**	**-**	**866**
Income taxes	**867**	**82**	**-**	**949**	**(168)**	**-**	**781**
Segment net income (loss)	**1,462**	**124**	**-**	**1,586**	**(11)**	**(2)**	**1,573**
Total assets	**38,825**	**2,691**	**(110)**	**41,406**	**1,933**	**(481)**	**42,858**
Gross property additions	**2,561**	**501**	**(16)**	**3,046**	**26**	**-**	**3,072**

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2005				(in millions)			
Operating revenues	$13,157	$ 781	$(660)	$13,278	$ 393	$(117)	$13,554
Depreciation and amortization	1,083	54	-	1,137	39	-	1,176
Interest income	30	2	-	32	5	(1)	36
Interest expense	567	79	-	646	101	-	747
Income taxes	827	72	-	899	(304)	-	595
Segment net income (loss)	1,398	115	-	1,513	80	(2)	1,591
Total assets	36,335	2,303	(179)	38,459	1,751	(333)	39,877
Gross property additions	2,177	241	-	2,418	58	-	2,476

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2004				(in millions)			
Operating revenues	$11,300	$ 701	$(536)	$11,465	$ 375	$(111)	$11,729
Depreciation and amortization	857	51	-	908	41	-	949
Interest income	24	1	-	25	4	(2)	27
Interest expense	518	66	-	584	83	-	667
Income taxes	802	73	-	875	(290)	-	585
Segment net income (loss)	1,309	112	-	1,421	109	2	1,532
Total assets	33,517	2,067	(104)	35,480	1,895	(420)	36,955
Gross property additions	2,307	116	(415)	2,008	91	-	2,099

Products and Services

	Electric Utilities Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2006	**$11,801**	**$1,822**	**$465**	**$14,088**
2005	11,165	1,667	446	13,278
2004	9,732	1,341	392	11,465

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2006 and 2005 – including discontinued operations for net income and earnings per share – are as follows:

				Per Common Share (Note)			
						Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income	Basic Earnings	Dividends	High	Low
		(in millions)					
March 2006	**$3,063**	**$ 590**	**$262**	**$0.35**	**$0.3725**	**$35.89**	**$32.34**
June 2006	**3,592**	**807**	**385**	**0.52**	**0.3875**	**33.25**	**30.48**
September 2006	**4,549**	**1,358**	**738**	**0.99**	**0.3875**	**35.00**	**32.01**
December 2006	**3,152**	**469**	**188**	**0.25**	**0.3875**	**37.40**	**34.49**
March 2005	$2,787	$ 560	$323	$0.43	$0.3575	$34.34	$31.14
June 2005	3,120	721	387	0.52	0.3725	35.00	31.60
September 2005	4,358	1,277	722	0.97	0.3725	36.47	33.24
December 2005	3,289	404	159	0.21	0.3725	36.33	32.76

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2002 through 2006
Southern Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in millions)	**$ 14,356**	$ 13,554	$ 11,729	$ 11,018	$ 10,447
Total Assets (in millions)	**$ 42,858**	$ 39,877	$ 36,955	$ 35,175	$ 33,721
Gross Property Additions (in millions)	**$ 3,072**	$ 2,476	$ 2,099	$ 2,014	$ 2,728
Return on Average Common Equity (percent)	**14.26**	15.17	15.38	16.05	15.79
Cash Dividends Paid Per Share of Common Stock	**$ 1.535**	$ 1.475	$ 1.415	$ 1.385	$ 1.355
Consolidated Net Income (in millions):					
Continuing Operations	**$ 1,574**	$ 1,591	$ 1,529	$ 1,483	$ 1,315
Discontinued Operations	**(1)**	-	3	(9)	3
Total	**$ 1,573**	$ 1,591	$ 1,532	$ 1,474	$ 1,318
Earnings Per Share From Continuing Operations --					
Basic	**$ 2.12**	$ 2.14	$ 2.07	$ 2.04	$ 1.86
Diluted	**2.10**	2.13	2.06	2.03	1.85
Earnings Per Share Including Discontinued Operations --					
Basic	**$ 2.12**	$ 2.14	$ 2.07	$ 2.03	$ 1.86
Diluted	**2.10**	2.13	2.06	2.02	1.85
Capitalization (in millions):					
Common stock equity	**$ 11,371**	$ 10,689	$ 10,278	$ 9,648	$ 8,710
Preferred and preference stock	**744**	596	561	423	298
Mandatorily redeemable preferred securities	**-**	-	-	1,900	2,380
Long-term debt payable to affiliated trusts	**1,561**	1,888	1,961	-	-
Long-term debt	**10,942**	10,958	10,488	10,164	8,714
Total (excluding amounts due within one year)	**$ 24,618**	$ 24,131	$ 23,288	$ 22,135	$ 20,102
Capitalization Ratios (percent):					
Common stock equity	**46.2**	44.3	44.1	43.6	43.3
Preferred and preference stock	**3.0**	2.5	2.4	1.9	1.5
Mandatorily redeemable preferred securities	**-**	-	-	8.6	11.8
Long-term debt payable to affiliated trusts	**6.3**	7.8	8.4	-	-
Long-term debt	**44.5**	45.4	45.1	45.9	43.4
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 15.24**	$ 14.42	$ 13.86	$ 13.13	$ 12.16
Market price per share:					
High	**37.40**	36.47	33.96	32.00	31.14
Low	**30.48**	31.14	27.44	27.00	23.22
Close (year-end)	**36.86**	34.53	33.52	30.25	28.39
Market-to-book ratio (year-end) (percent)	**241.9**	239.5	241.8	230.4	233.5
Price-earnings ratio (year-end) (times)	**17.4**	16.1	16.2	14.8	15.3
Dividends paid (in millions)	**$ 1,140**	$ 1,098	$ 1,044	$ 1,004	$ 958
Dividend yield (year-end) (percent)	**4.2**	4.3	4.2	4.6	4.8
Dividend payout ratio (percent)	**72.4**	69.0	68.3	67.7	72.8
Shares outstanding (in thousands):					
Average	**743,146**	743,927	738,879	726,702	708,161
Year-end	**746,270**	741,448	741,495	734,829	716,402
Stockholders of record (year-end)	**110,259**	118,285	125,975	134,068	141,784
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,706**	3,642	3,600	3,552	3,496
Commercial	**596**	586	578	564	553
Industrial	**15**	15	14	14	14
Other	**5**	5	5	6	5
Total	**4,322**	4,248	4,197	4,136	4,068
Employees (year-end)	**26,091**	25,554	25,642	25,762	26,178

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
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	2006	2005	2004	2003	2002
Operating Revenues (in millions):					
Residential	**$ 4,716**	$ 4,376	$ 3,848	$ 3,565	$ 3,556
Commercial	**4,117**	3,904	3,346	3,075	3,007
Industrial	**2,866**	2,785	2,446	2,146	2,078
Other	**102**	100	92	89	87
Total retail	**11,801**	11,165	9,732	8,875	8,728
Sales for resale	**1,822**	1,667	1,341	1,358	1,168
Total revenues from sales of electricity	**13,623**	12,832	11,073	10,233	9,896
Other revenues	**733**	722	656	785	551
Total	**$ 14,356**	$ 13,554	$ 11,729	$ 11,018	$ 10,447
Kilowatt-Hour Sales (in millions):					
Residential	**52,383**	51,082	49,702	47,833	48,784
Commercial	**52,987**	51,857	50,037	48,372	48,250
Industrial	**55,044**	55,141	56,399	54,415	53,851
Other	**920**	996	1,005	998	1,000
Total retail	**161,334**	159,076	157,143	151,618	151,885
Sales for resale	**40,089**	37,801	35,239	40,520	32,551
Total	**201,423**	196,877	192,382	192,138	184,436
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**9.00**	8.57	7.74	7.45	7.29
Commercial	**7.77**	7.53	6.69	6.36	6.23
Industrial	**5.21**	5.05	4.34	3.94	3.86
Total retail	**7.31**	7.02	6.19	5.85	5.75
Sales for resale	**4.54**	4.41	3.81	3.35	3.59
Total sales	**6.76**	6.52	5.76	5.33	5.37
Average Annual Kilowatt-Hour Use Per Residential Customer	**14,235**	14,084	13,879	13,562	14,036
Average Annual Revenue Per Residential Customer	**$ 1,282**	$ 1,207	$ 1,074	$ 1,011	$ 1,023
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**41,785**	40,509	38,622	38,679	36,353
Maximum Peak-Hour Demand (megawatts):					
Winter	**30,958**	30,384	28,467	31,318	25,939
Summer	**35,890**	35,050	34,414	32,949	32,355
System Reserve Margin (at peak) (percent)	**17.1**	14.4	20.2	21.4	13.3
Annual Load Factor (percent)	**60.8**	60.2	61.4	62.0	51.1
Plant Availability (percent):					
Fossil-steam	**89.3**	89.0	88.5	87.7	84.8
Nuclear	**91.5**	90.5	92.8	94.4	90.3
Source of Energy Supply (percent):					
Coal	**66.7**	67.1	64.6	66.4	65.7
Nuclear	**13.9**	14.0	14.4	14.8	14.7
Hydro	**1.9**	3.1	2.9	3.8	2.6
Oil and gas	**12.7**	10.7	10.9	8.8	11.4
Purchased power	**4.8**	5.1	7.2	6.2	5.6
Total	**100.0**	100.0	100.0	100.0	100.0

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ALABAMA POWER COMPANY

FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-104 to II-134) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 Alabama Power Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Birmingham, Alabama
February 26, 2007

OVERVIEW

Business Activities

Alabama Power Company (the Company) 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.

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and restoration following major storms.

In December 2006, the Company filed for an increase in retail base rates under Rate Stabilization and Equalization Plan (Rate RSE) based on a forward-looking test period. This increase became effective with billings beginning in January 2007. This and other regulatory actions are expected to assist the Company's continued focus on providing reliable electrical service to customers while maintaining a stable financial position.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2006 exceeded all targets on these reliability measures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal. The Company's 2006 results compared with its targets for each of these indicators are reflected in the following chart.

Key Performance Indicator	2006 Target Performance	**2006 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile**
Peak Season EFOR	2.75% or less	**0.76%**
Net Income	$502 million	**$518 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's financial performance remained strong in 2006 despite the challenges of rising costs. The Company's net income after dividends on preferred and preference stock of $518 million in 2006 increased $10 million (1.9 percent) over the prior year. This improvement is primarily due to retail and wholesale revenue growth offset by higher non-fuel operating expenses and increased interest expense.

The Company's 2005 net income after dividends on preferred stock was $508 million, representing a $27 million (5.6 percent) increase from the prior year. This improvement was primarily due to retail and wholesale revenue growth and increases in transmission revenues, partially offset by higher non-fuel operating expenses.

The Company's 2004 net income after dividends on preferred stock was $481 million, representing an $8 million (1.8 percent) increase from the prior year. This improvement was primarily due to retail sales growth, increases in other revenues, and lower interest expense, partially offset by higher non-fuel operating expenses.

RESULTS OF OPERATIONS

A condensed income statement is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	2006	2005	2004
	(in millions)			
Operating revenues	$5,015	$367	$412	$276
Fuel	1,673	216	271	119
Purchased power	426	(31)	44	98
Other operations and maintenance	1,097	53	97	26
Depreciation and amortization	451	24	1	13
Taxes other than income taxes	258	9	6	14
Total operating expenses	3,905	271	419	270
Operating income	1,110	96	(7)	6
Total other income and (expense)	(237)	(40)	6	30
Income taxes	330	46	(29)	23
Net income	543	10	28	13
Dividends on preferred and preference stock	25	–	1	5
Net income after dividends on preferred and preference stock	$ 518	$ 10	$ 27	$ 8

Revenues

Operating Revenues

Operating revenues for 2006 were $5.0 billion, reflecting a $367 million increase from 2005. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2006	2005	2004
	(in millions)		
Retail -- prior year	$3,621	$3,293	$3,051
Change in -			
Base rates	43	35	41
Sales growth	42	50	48
Weather	20	18	12
Fuel cost recovery and other	270	225	141
Retail -- current year	3,996	3,621	3,293
Sales for resale --			
Non-affiliates	635	551	484
Affiliates	216	289	308
Total sales for resale	851	840	792
Other operating revenues	168	187	151
Total operating revenues	$5,015	$4,648	$4,236
Percent change	7.9%	9.7%	7.0%

Retail revenues in 2006 were $4.0 billion. These revenues increased $375 million (10.3 percent) in 2006, $328 million (10.0 percent) in 2005, and $242 million (7.9 percent) in 2004. These increases were primarily due to increased fuel revenue and retail base rate increases of 2.6 percent in January 2006, 1.0 percent in January 2005, and 0.8 percent in July 2004. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Sales for resale to non-affiliates are predominantly unit power sales under long-term contracts to Florida utilities. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales customers, influence changes in these sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. These capacity and energy components of the unit power sales contracts were as follows:

	2006	2005	2004
		(in thousands)	
Unit power -			
Capacity	**$153,581**	$147,609	$134,615
Energy	**198,189**	169,080	146,809
Total	**$351,770**	$316,689	$281,424

No significant declines in the amount of capacity revenues are scheduled until the termination of the contracts in May 2010.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. Revenues associated with other power sales to non-affiliates were as follows:

	2006	2005	2004
		(in thousands)	
Other power sales -			
Capacity and other	**$136,966**	$116,181	$ 90,673
Variable cost of energy	**145,816**	118,537	111,742
Total	**$282,782**	$234,718	$202,415

Revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC) as approved by the Federal Energy Regulatory Commission (FERC). In 2006, sales for resale revenues decreased $72.9 million primarily due to a 16.7 percent decrease in price and a 10.3 percent decrease in kilowatt-hour (KWH) sales to affiliates as a result of a decrease in the availability of the Company's generating resources because of an increase in customer demand within the Company's service territory. In 2005, sales for resale revenues decreased $19.4 million primarily due to a 20.7 percent decrease in KWH sales to affiliates as a result of a decrease in the availability of the Company's generating resources due to an increase in customer demand within the Company's service territory. Sales for resale revenues increased $31.1 million in 2004 due to increases in fuel-related expenses. Excluding the capacity revenues, these transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause.

Other operating revenues in 2006 decreased $17.6 million (9.5 percent) from 2005 primarily due to a decrease of $14.6 million in revenues from gas-fueled co-generation steam facilities primarily as a result of lower gas prices. In 2005, other operating revenues increased $35.0 million (23.2 percent) from 2004 due to an increase of $20 million in revenues from gas-fueled co-generation steam facilities primarily as a result of higher gas prices, a $7.7 million increase in transmission revenues, and a $3.9 million increase from rent from associated companies primarily related to leased transmission facilities. Other operating revenues in 2004 increased $7.0 million (4.9 percent) from 2003 due to an increase of $7.7 million in revenues from gas-fueled co-generation steam facilities primarily as a result of higher gas prices, and a $2.4 million increase in revenues from rent from electric property offset by a $2.0 million decrease in transmission revenues. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2006 and the percent change by year were as follows:

	KWH	Percent Change		
	2006	2006	2005	2004
	(in millions)			
Residential	**18,633**	**3.1%**	4.1%	2.4%
Commercial	**14,355**	**2.1**	1.7	2.8
Industrial	**23,187**	**(0.7)**	2.2	5.8
Other	**200**	**0.4**	0.2	(2.4)
Total retail	**56,375**	**1.2**	2.7	3.9
Sales for resale -				
Non-affiliates	**15,978**	**3.5**	(0.3)	(9.4)
Affiliates	**5,145**	**(10.3)**	(20.7)	(23.2)
Total	**77,498**	**0.8**	(0.1)	(2.2)

Retail energy sales in 2006 were 1.2 percent higher than in 2005. Energy sales in the residential and commercial sectors led the growth with a 3.1 percent and a 2.1 percent increase, respectively, in 2006 due primarily to weather-driven increased demand. Industrial sales decreased 0.7 percent during the year as several large textile facilities discontinued or substantially reduced their operations in 2006. In addition, industrial sales decreased due to pulp and paper customers utilizing self-generation as a result of lower gas prices during the year compared to 2005.

Retail energy sales in 2005 were 2.7 percent higher than 2004 despite interruptions during Hurricanes Dennis and Katrina. Energy sales in the residential sector led the growth with a 4.1 percent increase in 2005 due primarily to increased demand. Commercial sales increased 1.7 percent in 2005 primarily due to continued customer growth. Industrial sales increased 2.2 percent during the year with chemical, primary metals and automotive leading the growth in industrial energy consumption. In addition, the paper sector chose to purchase rather than self-generate which contributed to increased sales.

Retail energy sales in the residential sector grew by 2.4 percent in 2004 primarily due to continued customer growth and a return to normal summer temperatures. Commercial sales increased 2.8 percent in 2004 primarily due to continued customer growth. Industrial sales rebounded 5.8 percent during the year with primary metals, chemical, and paper sectors leading the growth.

Expenses

Fuel and Purchased Power

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Details of the Company's generation, fuel, and purchased power are as follows:

	2006	2005	2004
Total generation (billions of KWH) --	**72.0**	71.2	70.2
Total purchased power (billions of KWH) --	**8.9**	8.7	10.2
Sources of generation (percent) --			
Coal	**68**	67	65
Nuclear	**19**	19	19
Gas	**9**	8	10
Hydro	**4**	6	6
Average cost of fuel, source (cents per net KWH) --			
Coal	**2.09**	1.85	1.58
Nuclear	**0.47**	0.46	0.46
Gas	**7.87**	7.43	4.69
Average cost of fuel, generated (cents per net KWH) --	**2.27**	2.02	1.69
Average cost of purchased power (cents per net KWH) --	**5.98**	6.49	4.79

Fuel and purchased power expenses were $2.1 billion in 2006, an increase of $184.1 million (9.6 percent) above the prior year costs. This increase was the result of a $128.7 million increase in the cost of fuel and a $55.4 million increase related to total KWH generated and purchased.

Fuel and purchased power expenses were $1.9 billion in 2005, an increase of $315.4 million (19.7 percent) above the prior year costs. This increase was the result of a $367.4 million increase in the cost of fuel offset by a $52.0 million decrease related to total KWH generated and purchased.

Fuel and purchased power expenses were $1.6 billion in 2004, an increase of $216.3 million (15.6 percent) above the prior year costs. This increase was the result of a $218.4 million increase in the cost of fuel offset by a $2.1 million decrease related to total KWH generated and purchased.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. Purchased power from non-affiliates decreased $64.7 million (34.3 percent) in 2006. This decrease was due to a 26.8 percent decrease in the amount of energy purchased and a 10.3 percent decrease in purchased power prices over the previous year. In 2005, purchased power from non-affiliates increased $2.5 million (1.0 percent) due to a 14.3 percent increase in purchased power prices over the previous year. In 2004, purchased power from non-affiliates increased $75 million (68.0 percent) due to a 71.7 percent increase in energy purchased offset by a 1.9 percent decrease in purchased power prices compared to 2003.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's energy cost recovery clause. The Company continuously monitors the under/over recovered balance and files for a revised fuel rate when management deems appropriate. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Other Operating Expenses

Other Operations and Maintenance

In 2006, other operations and maintenance expenses increased $52.8 million (5.1 percent) primarily due to an $18.8 million increase in administrative and general expenses related to employee benefits, a $10.1 million increase in nuclear production expense related to both routine operation and scheduled outage costs, a $9.8 million increase in transmission and distribution expense related to overhead and underground line costs, and a $5.4 million increase in steam production expense related to environmental costs. In 2005, other operations and maintenance expenses increased $96.7 million (10.2 percent). This increase was primarily due to an increase in transmission and distribution expense of $37.3 million as a result of the Alabama Public Service Commission (PSC) accounting order to offset the costs of the damage from Hurricane Ivan in September 2004 and to restore a balance in the natural disaster reserve. See Notes 1 and 3 to the financial statements under "Natural Disaster Reserve" and "Natural Disaster Cost Recovery," respectively, for additional information. In addition, steam production expense increased $28.1 million related to scheduled outage costs and administrative and general expenses increased $20.7 million related to employee benefits. In 2004, other operations and maintenance expenses increased $26.6 million (2.9 percent) primarily due to an increase in administrative and general expenses related to employee benefits.

Depreciation and Amortization

Depreciation and amortization expenses increased $24.5 million (5.7 percent) in 2006 primarily due to additions to property, plant, and equipment. In 2005, depreciation and amortization expenses remained relatively flat compared to the prior year, increasing only $0.6 million (0.1 percent). During 2005, the depreciation rates used by the Company were adjusted based on a periodic study conducted by external experts that is used to determine the appropriateness of the rates utilized. Also in 2005, additions to property, plant, and equipment, which resulted in increased depreciation expense, were offset by the suspension of $18 million in nuclear decommissioning costs by the Alabama PSC due to the extension of the operating license for both units at Plant Farley. See FUTURE EARNINGS POTENTIAL – "Nuclear Relicensing" and Note 1 to the financial statements under "Nuclear Decommissioning" for additional information. In 2004, depreciation and amortization expenses increased $13 million (3.1 percent) primarily due to an increase in utility plant in service. This increase reflects the impact of additions to property, plant, and equipment.

Taxes other than Income Taxes

Taxes other than income taxes increased $9.3 million (3.7 percent) in 2006, $6.0 million (2.5 percent) in 2005, and $14.4 million (6.3 percent) in 2004, primarily due to increases in state and municipal public utility license taxes which are directly related to the increase in retail revenues.

Other Income and (Expense)

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) decreased $2.0 million (10.0 percent) in 2006 primarily due to the timing of construction expenditures compared to the prior year. AFUDC increased $4.1 million (25.6 percent) and $3.5 million (28.2 percent) in 2005 and 2004, respectively, primarily due to increases in the amount of construction work in progress over the prior year. See Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest

Interest expense, net of amounts capitalized increased $38.7 million (19.6 percent) in 2006 primarily due to higher interest rates and an increase in the average debt outstanding during the year. Interest expense, net of amounts capitalized, increased $3.8 million (2.0 percent) in 2005 due to an increase in average debt outstanding during the year. Interest expense, net of amounts capitalized, decreased $20.7 million (9.7 percent) in 2004 due to refinancing activities.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. Rate RSE is based on annual projected costs, including estimates for inflation. When historical costs are included, or when inflation exceeds the projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. The inflation rate has been relatively low in recent years and any adverse effect of inflation on the Company has not been substantial.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in the State of Alabama and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for electricity relating to purchased power agreements (PPAs), interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Assuming normal weather, sales to retail customers are projected to grow approximately 1.1 percent annually on average during 2007 through 2011.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama after the Company was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required the Company to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by the Company, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted the plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. These regulatory revisions have been adopted by the State of Alabama. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the State of Alabama's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act, and the Endangered Species Act. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, the Company had invested approximately $1.2 billion in capital projects to comply with these requirements, with annual totals of $260 million, $256 million, and $177 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $505 million, $533 million, and $549 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate impact of compliance cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $1.0 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2, NO_x, and mercury emissions, maintain compliance with existing regulations, and meet new requirements.

Approximately $638 million of these expenditures related to reducing NO_x emissions pursuant to state and federal requirements were in connection with the EPA's one-hour ozone standard and the 1998 regional NO_x reduction rules. In 2004, the regional NO_x reduction rules were implemented for the northern two-thirds of Alabama. See Note 3 to the financial statements under "Retail Regulatory Matters" for information regarding the Company's recovery of costs associated with environmental laws and regulations.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that were designated as nonattainment under the eight-hour ozone standard included Jefferson and Shelby Counties, near and including Birmingham. The Birmingham area was redesignated to attainment with the eight-hour ozone standard by the EPA on June 12, 2006, and the EPA subsequently approved a maintenance plan for the area to address future exceedances of the standard. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment are currently required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within the Company's service area, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA is expected to publish its final rule for implementation of the existing fine particulate matter standard in early 2007. State plans for addressing the nonattainment designations under the existing standard are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. On September 21, 2006, the EPA published a final rule lowering the 24-hour fine particulate matter air quality standard even further and plans to designate nonattainment areas based on the new standard by December 2009. The final outcome of this matter cannot be determined at this time.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Alabama, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed, and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change, and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010 - 2012. Southern Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, Southern Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $3.9 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $14.6 million for the Company, of which $3.1 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the Company, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11 million previously paid for interconnection facilities, with interest. The Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Market-Based Rate Authority" and "Generation Interconnection Agreements" above for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

Hydro Relicensing

In July 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expire in July and August of 2007.

In 2006, the Company initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license will be filed with the FERC in 2011.

Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. If the FERC does not act on the Company's new license application prior to the expiration of the existing license, then the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until a new license is issued.

The timing and final outcome of the Company's relicense applications cannot now be determined.

Nuclear Relicensing

The Company filed an application with the Nuclear Regulatory Commission (NRC) in September 2003 to extend the operating license for Plant Farley for an additional 20 years. In May 2005, the NRC granted the Company a 20-year extension of the operating license for both units at Plant Farley. As a result of the license extension, amounts previously contributed to the external trust are currently projected to be adequate to meet the decommissioning obligations. Therefore, in June 2005, the Alabama PSC approved the Company's request to suspend, effective January 1, 2005, the inclusion in its annual cost of service of $18 million in decommissioning costs and to also suspend the associated obligation to make semi-annual contributions to the external trust. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

PSC Matters

Retail Rate Adjustments

In October 2005, the Alabama PSC approved a revision to the Rate RSE requested by the Company. Effective January 2007 and thereafter, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4 percent per year and any annual adjustment is limited to

5 percent. Rates remain unchanged when the projected return on retail common equity ranges between 13.0 percent and 14.5 percent. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range. The Company made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007, effective in January, is 4.76 percent, or $193 million annually. Under terms of Rate RSE, the maximum increase for 2008 cannot exceed 3.24 percent. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for further information.

The Company's retail rates, approved by the Alabama PSC, also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under Rate Certificated New Plant (Rate CNP). In October 2004, the Alabama PSC amended Rate CNP to also allow for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism began operation in January 2005 and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operation and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.0 percent in January 2005, 1.2 percent in January 2006, and 0.6 percent in January 2007. It is currently anticipated that retail rates will increase approximately 2.5 percent in 2008.

Effective July 2004, the Company's retail rates were increased by approximately 0.8 percent, or $25 million annually, under Rate CNP for new certificated PPAs. In April 2005, an annual adjustment to Rate CNP decreased retail rates by approximately 0.5 percent, or $19 million annually. The annual true-up adjustment effective in April 2006 increased retail rates by 0.5 percent, or $19 million annually. Based on the Company's February 2007 filing, there will be no rate adjustment associated with the annual true-up adjustment in April 2007. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. As a result of increased fuel costs for coal, gas, and uranium, the Company filed a fuel cost recovery increase under the provisions of its energy cost recovery rate (Rate ECR). In December 2005, the Alabama PSC approved an increase of the energy billing factor for retail customers from 1.788 cents per KWH to 2.400 cents per KWH, effective with billings beginning January 2006 for the 24-month period ending December 31, 2007. Thereafter, the Rate ECR factor will increase absent a contrary order by the Alabama PSC. This change to the billing factor in 2006 represents on average an increase of approximately $6.12 per month for a customer billing of 1,000 KWH. This approved increase was intended to allow for the recovery of energy costs based on an estimate of future energy costs, as well as the collection of the existing under recovered energy costs by the end of 2007. In addition, during 2007, the Company will be allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation.

The Company's under recovered fuel costs as of December 31, 2006 totaled $301.0 million as compared to $285.1 million at December 31, 2005. As a result of the Alabama PSC order, the Company reclassified $301.0 million and $186.9 million of the under-recovered regulatory clause revenues from current assets to deferred charges and other assets in the balance sheets as of December 31, 2006 and December 31, 2005, respectively. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable costs and amounts billed in current regulated rates. Accordingly, this approved increase in the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

Natural Disaster Cost Recovery

The Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. On July 10, 2005 and August 29, 2005, Hurricanes Dennis and Katrina, respectively, hit the coast of Alabama and continued north through the state, causing significant damage in parts of the service territory of the Company. Approximately 241,000 and 637,000 of the Company's 1.4 million customers were without electrical service immediately after Hurricanes Dennis and Katrina, respectively. The Company sustained significant damage to its distribution and transmission facilities during these storms.

In August 2005, the Company received approval from the Alabama PSC to defer the Hurricane Dennis storm-related operations and maintenance costs (approximately $28 million), which resulted in a negative balance in the natural disaster reserve (NDR). In October 2005, the Company also received similar approval from the Alabama PSC to defer the Hurricane Katrina storm-related operations and maintenance costs (approximately $30 million). See Note 1 and Note 3 to the financial statements under "Natural Disaster Reserve" and "Natural Disaster Cost Recovery," respectively, for additional information on these reserves. The natural disaster reserve deficit balance at December 31, 2005 was $50.6 million.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted NDR and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components beginning in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. Assuming no additional storms, the Company currently expects that the target reserve balance could be achieved within five years. The second component of the NDR charge is intended to allow recovery of the existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

As of December 31, 2006, the Company had recovered $49.5 million of the costs allowed for storm-recovery activities and the deficit balance in the natural disaster reserve account totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of the NDR charge. At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities."

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income but will increase annual cash flow.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pre-tax pension income of approximately $13 million, $21 million, and $36 million in 2006, 2005, and 2004, respectively. Postretirement benefit costs for the Company were $28 million, $28 million, and $22 million in 2006, 2005, and 2004, respectively. Postretirement benefit costs are expected to trend upward. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in Internal Revenue Service (IRS) or Alabama Department of Revenue interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123(R), "Share-Based Payment," using the modified prospective method. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $183 million with respect to its overfunded defined benefit plan and additional liabilities of $10 million and $147 million, respectively, related to its underfunded non-qualified pension plans and other postretirement benefit plans. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007. The adoption of FIN 48 did not have a material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Net cash flow from operating activities totaled $956 million, $908 million, and $1,014 million for 2006, 2005, and 2004, respectively. The $48 million increase for 2006 in operating activities primarily relates to higher recovery rates for fuel and purchased power partially offset by the timing of payments for operation expenses. The $106 million decrease for 2005 in operating activities primarily relates to an increase in under recovered fuel cost and storm damage costs related to Hurricanes Dennis and Katrina. These increases were partially offset by the deferral of income tax liabilities arising from accelerated depreciation deductions. Fuel and storm damage costs are recoverable in future periods. Under recovered fuel cost is included in the balance sheets as under recovered regulatory clause revenue and deferred under recovered regulatory clause revenues. Under recovered storm damage cost is included in the balance sheets as other current assets and other regulatory assets. See FUTURE EARNINGS POTENTIAL – "Retail Fuel Cost Recovery" and "Natural Disaster Cost Recovery" for additional information.

Significant balance sheet changes for 2006 include an increase of $697 million in gross plant and an increase of $279 million in long-term debt. In 2005, significant balance sheet changes included an increase of $668 million in gross plant.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.1 percent in 2006, 42.2 percent in 2005, and 42.6 percent in 2004. See Note 6 to the financial statements for additional information.

The Company has maintained investment grade ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference stock.

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 operating cash flows. In recent years, the Company has primarily utilized unsecured debt, common stock, preferred and preference stock, and preferred securities. However, the type and timing of any financings, if needed, will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Alabama PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt as well as cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2007, the Company had approximately $16 million of cash and cash equivalents and $965 million of unused credit arrangements with banks, as described below. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including commercial paper programs, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of $965 million, of which $365 million will expire at various times during 2007. $198 million of the credit facilities expiring in 2007 allow for the execution of term loans for an additional one-year period. The remaining $600 million of credit facilities expire in 2011. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

As of December 31, 2006, the Company had $120 million in commercial paper outstanding, and no extendible commercial notes outstanding. As of December 31, 2005, the Company had $136 million in commercial paper outstanding, $55 million in extendible commercial notes outstanding, and $125 million in loans outstanding under an uncommitted credit arrangement.

Financing Activities

During 2006, the Company issued $950 million of long-term debt and six million new shares of preference stock at $25.00 stated capital per share and realized proceeds of $150 million. In addition, the Company issued three million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $120 million. The proceeds of these issuances were used to repay $546.5 million of senior notes and $3.0 million of obligations related to pollution control bonds, to repay short-term indebtedness, and for other general corporate purposes.

On February 6, 2007, the Company issued $200 million of long-term senior notes. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, the Company, along with all members of the Southern Company power pool, is party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for the Company and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price Risk

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps that have been designated as hedges. The weighted average interest rate on $440 million of long-term variable interest rate exposure that has not been hedged at January 1, 2007 was 5.50 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $4.4 million at January 1, 2007. Subsequent to December 31, 2006, interest rate swaps hedging approximately $536 million of floating rate pollution control bonds matured, increasing the Company's variable rate exposure by $536 million. As a result, the effect of a 100 basis point change in interest rates for all currently unhedged variable rate long-term debt increased to approximately $9.8 million. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

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 and, to a lesser extent, into similar contracts for gas purchases. The Company has implemented fuel hedging programs at the instruction of the Alabama PSC.

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

At December 31, 2006, exposure from these activities was not material to the Company's financial position, results of operations, or cash flows. The changes in fair value of energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in thousands)	
Contracts beginning of year	**$ 28,978**	$ 4,017
Contracts realized or settled	**45,031**	(38,320)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**(106,637)**	63,281
Contracts end of year	**$ (32,628)**	$ 28,978

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

Source of 2006 Year-End Valuation Prices

	Total Fair Value	Maturity 2007	2008-2009
	(in thousands)		
Actively quoted	**$(33,304)**	**$(30,776)**	**$(2,528)**
External sources	**676**	**676**	**-**
Models and other methods	**-**	**-**	**-**
Contracts end of year	**$(32,628)**	**$(30,100)**	**$(2,528)**

Unrealized gains and losses from mark-to-market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery clause. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$(33,267)
Accumulated other comprehensive income	676
Net income	(37)
Total fair value	$(32,628)

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.2 billion for 2007, $1.3 billion for 2008, and $1.3 billion for 2009. Environmental expenditures included in these amounts are $505 million, $533 million, and $549 million for 2007, 2008, and 2009, respectively (including $202 million on selective catalytic reduction facilities and $1.2 billion on scrubbers, which reduce SO_2 emissions). In addition, over the next three years, the Company estimates spending $317 million on Plant Farley (including $211 million for nuclear fuel), $941 million on distribution facilities, and $405 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and 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. As a result of NRC requirements, the Company and Georgia Power have external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition to the funds required for the Company's construction program, approximately $1.3 billion will be required by the end of 2009 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower-cost capital if market conditions permit.

As discussed in Note 1 to the financial statements under "Nuclear Fuel Disposal Costs," in 1993 the U.S. Department of Energy implemented a special assessment over a 15-year period on utilities with nuclear plants to be used for the decontamination and decommissioning of its nuclear fuel enrichment facilities. The final installment occurred in 2006.

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

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments, are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[a] --					
Principal	$ 669	$ 660	$ 300	$3,191	$ 4,820
Interest	249	413	365	3,315	4,342
Other derivative obligations[b] --					
Commodity	33	3	-	-	36
Interest	4	-	-	-	4
Preferred and preference stock dividends[c]	33	65	65	-	163
Operating leases	28	48	25	26	127
Purchase commitments[d]--					
Capital[e]	1,191	2,618	-	-	3,809
Coal	1,094	1,301	1,147	2,145	5,687
Nuclear fuel	26	69	84	67	246
Natural gas[f]	342	454	99	123	1,018
Purchased power	88	179	37	-	304
Long-term service agreements	17	35	36	67	155
Postretirement benefits[g]	25	47	-	-	72
Total	$3,799	$5,892	$2,158	$8,934	$20,783

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2006, 2005, and 2004 were $1.10 billion, $1.04 billion, and $947 million, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth and retail rates, storm damage cost recovery and repairs, fuel cost recovery, environmental regulations and expenditures, earnings growth, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, completion of construction projects, impacts of adoption of new accounting rules, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax, 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, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- 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 ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$3,995,731**	$3,621,421	$3,292,828
Sales for resale --			
Non-affiliates	**634,552**	551,408	483,839
Affiliates	**216,028**	288,956	308,312
Other revenues	**168,417**	186,039	151,012
Total operating revenues	**5,014,728**	4,647,824	4,235,991
Operating Expenses:			
Fuel	**1,672,831**	1,457,301	1,186,472
Purchased power --			
Non-affiliates	**124,022**	188,733	186,187
Affiliates	**302,045**	268,751	226,697
Other operations	**720,296**	682,308	634,030
Maintenance	**376,682**	361,832	313,407
Depreciation and amortization	**451,018**	426,506	425,906
Taxes other than income taxes	**258,135**	248,854	242,809
Total operating expenses	**3,905,029**	3,634,285	3,215,508
Operating Income	**1,109,699**	1,013,539	1,020,483
Other Income and (Expense):			
Allowance for equity funds used during construction	**18,253**	20,281	16,141
Interest income	**20,897**	17,144	15,677
Interest expense, net of amounts capitalized	**(236,045)**	(197,367)	(193,590)
Interest expense to affiliate trusts	**(16,237)**	(16,237)	(16,191)
Other income (expense), net	**(23,758)**	(20,461)	(24,728)
Total other income and (expense)	**(236,890)**	(196,640)	(202,691)
Earnings Before Income Taxes	**872,809**	816,899	817,792
Income taxes	**330,345**	284,715	313,024
Net Income	**542,464**	532,184	504,768
Dividends on Preferred and Preference Stock	**24,734**	24,289	23,597
Net Income After Dividends on Preferred and Preference Stock	**$ 517,730**	$ 507,895	$ 481,171

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005, and 2004
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 542,464**	$ 532,184	$ 504,768
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization	**524,313**	498,914	497,010
Deferred income taxes and investment tax credits, net	**(27,562)**	106,765	252,858
Deferred revenues	**(1,274)**	(12,502)	(11,510)
Allowance for equity funds used during construction	**(18,253)**	(20,281)	(16,141)
Pension, postretirement, and other employee benefits	**(15,196)**	(22,117)	(31,184)
Stock option expense	**4,848**	-	-
Tax benefit of stock options	**610**	17,400	10,672
Hedge settlements	**18,006**	(21,445)	2,241
Storm damage accounting order	**-**	48,000	-
Other, net	**12,832**	(15,491)	26,826
Changes in certain current assets and liabilities --			
Receivables	**(33,260)**	(255,481)	(126,432)
Fossil fuel stock	**(28,179)**	(44,632)	30,130
Materials and supplies	**(25,711)**	(16,935)	(26,229)
Other current assets	**38,645**	1,199	7,438
Accounts payable	**(49,725)**	80,951	(31,899)
Accrued taxes	**1,124**	(5,381)	(24,568)
Accrued compensation	**(6,157)**	3,273	(7,041)
Other current liabilities	**18,486**	33,675	(42,544)
Net cash provided from operating activities	**956,011**	908,096	1,014,395
Investing Activities:			
Property additions	**(933,306)**	(860,807)	(768,334)
Nuclear decommissioning trust fund purchases	**(286,551)**	(224,716)	(269,277)
Nuclear decommissioning trust fund sales	**285,685**	223,850	248,992
Cost of removal net of salvage	**(40,834)**	(61,314)	(37,369)
Other	**(1,777)**	(9,738)	(5,008)
Net cash used for investing activities	**(976,783)**	(932,725)	(830,996)
Financing Activities:			
Increase (decrease) in notes payable, net	**(195,609)**	315,278	-
Proceeds --			
Senior notes	**950,000**	250,000	900,000
Preferred and preference stock	**150,000**	-	100,000
Common stock issued to parent	**120,000**	40,000	40,000
Capital contributions	**27,160**	22,473	17,541
Gross excess tax benefit of stock options	**1,291**	-	-
Pollution control bonds	**-**	21,450	-
Redemptions --			
Senior notes	**(546,500)**	(225,000)	(725,000)
Pollution control bonds	**(2,950)**	(21,450)	-
Capital leases	**-**	(5)	(1,445)
Payment of preferred and preference stock dividends	**(24,318)**	(22,759)	(23,639)
Payment of common stock dividends	**(440,600)**	(409,900)	(437,300)
Other	**(24,635)**	(2,697)	(16,597)
Net cash provided from (used for) financing activities	**13,839**	(32,610)	(146,440)
Net Change in Cash and Cash Equivalents	**(6,933)**	(57,239)	36,959
Cash and Cash Equivalents at Beginning of Year	**22,472**	79,711	42,752
Cash and Cash Equivalents at End of Year	**$ 15,539**	$ 22,472	$ 79,711
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $7,930, $8,161, and $6,832 capitalized, respectively)	**$ 245,387**	$ 179,658	$ 188,556
Income taxes (net of refunds)	**345,803**	159,600	69,068

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

BALANCE SHEETS
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 15,539**	$ 22,472
Receivables --		
Customer accounts receivable	**323,202**	275,702
Unbilled revenues	**90,596**	95,039
Under recovered regulatory clause revenues	**32,451**	132,139
Other accounts and notes receivable	**49,708**	50,008
Affiliated companies	**70,836**	77,304
Accumulated provision for uncollectible accounts	**(7,091)**	(7,560)
Fossil fuel stock, at average cost	**153,120**	102,420
Vacation pay	**46,465**	44,893
Materials and supplies, at average cost	**255,664**	244,417
Prepaid expenses	**76,265**	58,845
Other	**66,663**	98,506
Total current assets	**1,173,418**	1,194,185
Property, Plant, and Equipment:		
In service	**15,997,793**	15,300,346
Less accumulated provision for depreciation	**5,636,475**	5,313,731
	10,361,318	9,986,615
Nuclear fuel, at amortized cost	**137,300**	127,199
Construction work in progress	**562,119**	469,018
Total property, plant, and equipment	**11,060,737**	10,582,832
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**47,486**	46,913
Nuclear decommissioning trusts, at fair value	**513,521**	466,963
Other	**35,980**	41,457
Total other property and investments	**596,987**	555,333
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**354,225**	388,634
Prepaid pension costs	**722,287**	515,281
Deferred under recovered regulatory clause revenues	**301,048**	186,864
Other regulatory assets	**279,661**	122,378
Other	**166,927**	144,400
Total deferred charges and other assets	**1,824,148**	1,357,557
Total Assets	**$14,655,290**	$13,689,907

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

BALANCE SHEETS
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 668,646**	$ 546,645
Notes payable	**119,670**	315,278
Accounts payable --		
Affiliated	**162,951**	190,744
Other	**263,506**	266,174
Customer deposits	**62,978**	56,709
Accrued taxes --		
Income taxes	**3,120**	63,844
Other	**29,696**	31,692
Accrued interest	**53,573**	46,018
Accrued vacation pay	**38,767**	37,646
Accrued compensation	**87,194**	92,784
Other	**79,907**	72,991
Total current liabilities	**1,570,008**	1,720,525
Long-term Debt (See accompanying statements)	**3,838,906**	3,560,186
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	**309,279**	309,279
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,116,575**	2,070,746
Deferred credits related to income taxes	**98,941**	101,678
Accumulated deferred investment tax credits	**188,582**	196,585
Employee benefit obligations	**375,940**	208,663
Asset retirement obligations	**476,460**	446,268
Other cost of removal obligations	**600,278**	600,104
Other regulatory liabilities	**399,822**	194,135
Other	**35,805**	23,966
Total deferred credits and other liabilities	**4,292,403**	3,842,145
Total Liabilities	**10,010,596**	9,432,135
Preferred and Preference Stock (See accompanying statements)	**612,407**	465,046
Common Stockholder's Equity (See accompanying statements)	**4,032,287**	3,792,726
Total Liabilities and Stockholder's Equity	**$14,655,290**	$13,689,907
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
2.65% to 2.80% due 2006	$ -	$ 520,000		
Floating rate (2.11% at 1/1/06) due 2006	-	26,500		
3.50% to 7.125% due 2007	**500,000**	500,000		
Floating rate (5.624% at 1/1/07) due 2007	**168,500**	168,500		
3.125% to 5.375% due 2008	**410,000**	410,000		
Floating rate (5.55% at 1/1/07) due 2009	**250,000**	250,000		
4.70% due 2010	**100,000**	100,000		
5.10% due 2011	**200,000**	-		
5.125% to 6.375% due 2016-2046	**2,325,000**	1,575,000		
Total long-term notes payable	**$3,953,500**	$3,550,000		
Other long-term debt --				
Pollution control revenue bonds --				
Variable rates (2.01% to 2.16% at 1/1/06) due 2015-2017	-	89,800		
5.50% due 2024	-	2,950		
Variable rates (3.91% to 4.07% at 1/1/07) due 2015-2031	**557,190**	467,390		
Total other long-term debt	**557,190**	560,140		
Capitalized lease obligations	**377**	564		
Unamortized debt premium (discount), net	**(3,515)**	(3,873)		
Total long-term debt (annual interest requirement -- $232.9 million)	**4,507,552**	4,106,831		
Less amount due within one year	**668,646**	546,645		
Long-term debt excluding amount due within one year	**$3,838,906**	$3,560,186	**43.6%**	43.8%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2006 and 2005
Alabama Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-term Debt Payable to Affiliated Trusts:				
4.75% to 5.5% due 2042 (annual interest requirement -- $16.2 million)	**309,279**	309,279	**3.5**	3.8
Preferred and Preference Stock:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**47,610**	47,610		
$1 par value -- 4.95% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value	**294,105**	294,105		
Outstanding - 1,250 shares: $100,000 stated value	**123,331**	123,331		
Preference stock				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63%				
- 6,000,000 shares (non-cumulative) $25 stated value	**147,361**	-		
Total preferred and preference stock (annual dividend requirement -- $32.7 million)	**612,407**	465,046	**7.0**	5.7
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 2006: 25,000,000 shares				
- 2005: 15,000,000 shares				
Outstanding - 2006: 12,250,000 shares	**490,000**	370,000		
- 2005: 9,250,000 shares				
Paid-in capital	**2,028,963**	1,995,056		
Retained earnings	**1,516,245**	1,439,144		
Accumulated other comprehensive income (loss)	**(2,921)**	(11,474)		
Total common stockholder's equity	**4,032,287**	3,792,726	**45.9**	46.7
Total Capitalization	**$8,792,879**	$8,127,237	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2006, 2005, and 2004
Alabama Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$290,000	$1,927,069	$1,291,558	$ (7,967)	$3,500,660
Net income after dividends on preferred stock	-	-	481,171	-	481,171
Issuance of common stock	40,000	-	-	-	40,000
Capital contributions from parent company	-	28,213	-	-	28,213
Other comprehensive income (loss)	-	-	-	(8,061)	(8,061)
Cash dividends on common stock	-	-	(437,300)	-	(437,300)
Other	-	(99)	5,620	-	5,521
Balance at December 31, 2004	330,000	1,955,183	1,341,049	(16,028)	3,610,204
Net income after dividends on preferred stock	-	-	507,895	-	507,895
Issuance of common stock	40,000	-	-	-	40,000
Capital contributions from parent company	-	39,873	-	-	39,873
Other comprehensive income (loss)	-	-	-	4,554	4,554
Cash dividends on common stock	-	-	(409,900)	-	(409,900)
Other	-	-	100	-	100
Balance at December 31, 2005	**370,000**	**1,995,056**	**1,439,144**	**(11,474)**	**3,792,726**
Net income after dividends on preferred and preference stock	-	-	**517,730**	-	**517,730**
Issuance of common stock	**120,000**	-	-	-	**120,000**
Capital contributions from parent company	-	**33,907**	-	-	**33,907**
Other comprehensive income (loss)	-	-	-	**(4,057)**	**(4,057)**
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	**12,610**	**12,610**
Cash dividends on common stock	-	-	**(440,600)**	-	**(440,600)**
Other	-	-	**(29)**	-	**(29)**
Balance at December 31, 2006	**$490,000**	**$2,028,963**	**$1,516,245**	**$ (2,921)**	**$4,032,287**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Alabama Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred and preference stock	**$517,730**	$507,895	$481,171
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $1,109, $(1,422) and $(2,482), respectively	**1,768**	(2,338)	(4,083)
Change in fair value of marketable securities, net of tax of $-, $- and $252, respectively	-	-	414
Changes in fair value of qualifying hedges, net of tax of $155, $5,523 and $(4,807), respectively	**255**	9,085	(7,906)
Less: Reclassification adjustment for amounts included in net income, net of tax of $(3,696), $(1,333) and $2,136, respectively	**(6,080)**	(2,193)	3,514
Total other comprehensive income (loss)	**(4,057)**	4,554	(8,061)
Comprehensive Income	**$513,673**	$512,449	$473,110

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. Southern Power constructs, acquires, and manages generation assets, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley. On January 4, 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its 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.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $266 million, $246 million, and $224 million during 2006, 2005, and 2004, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which Southern Nuclear operates the Company's Plant Farley and provides the following nuclear-related services at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, statistical analysis, employee relations, and other services with respect to business and operations. Costs for these services amounted to $162 million, $157 million, and $169 million during 2006, 2005, and 2004, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of expenses which were $8.6 million in 2006, $8.2 million in 2005, and $7.2 million in 2004. See Note 4 for additional information.

Southern Company held a 30 percent ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel, until July 2006, when the ownership interest was terminated. The Company purchases synthetic fuel from AFP for use at several of the Company's plants. Total fuel purchases through June 2006 and for the years ended 2005 and 2004 were $202.2 million, $265.7 million, and $236.9 million, respectively. Subsequent to the termination of the membership interest in AFP, the Company continued to purchase fuel from AFP in the amount of $244.4 million in 2006. In addition, the Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $56.5 million, $31.5 million, and $28.7 million in 2006, 2005, and 2004, respectively.

In June 2003, the Company entered into an agreement with Southern Power under which the Company operates and maintains Plant Harris at cost. In 2006, 2005, and 2004, the Company billed Southern Power $2.2 million, $1.9 million, and $1.8 million, respectively, for operation and maintenance. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2006, 2005, and 2004 totaled $61.7 million, $63.6 million, and $59.0 million, respectively. The Company also provides the fuel, at cost, associated with the PPA and the fuel cost recognized by the Company was $77.8 million in 2006, $81.3 million in 2005, and $65.7 million in 2004. Additionally, the Company recorded $8.3 million of prepaid capacity expenses included in other deferred charges and other assets in the balance sheets at December 31, 2006 and 2005. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with SouthernLINC Wireless to provide digital wireless communications services to the Company. Costs for these services amounted to $4.9 million, $5.7 million, and $5.3 million during 2006, 2005, and 2004, respectively.

Also, see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

The Company provides incidental services to, and receives such services from, other Southern Company subsidiaries which are generally minor in duration and/or amount. However, with the hurricane damage experienced by Georgia Power, Gulf Power and Mississippi Power in 2004 and 2005, assistance provided to aid in storm restoration, including Company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm restoration provided to Georgia Power and Gulf Power in 2004 and to Mississippi Power in 2005 was $2.4 million, $2.3 million, and $8.0 million, respectively. In 2004 and 2005, the Company received assistance from affiliated companies in the amount of $5.6 million and $5.0 million, respectively, for aid in major storm restoration. These activities were billed at cost.

The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate depending on the rate. See "Retail Regulatory Matters – Fuel Cost Recovery" in Note 3 for additional information.

The Company has a diversified base of customers. No single customer comprises 10 percent or more of revenues. For all periods presented, uncollectible accounts averaged less than one percent of revenues.

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" (SFAS No. 71). 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:

	2006	2005	Note
	(in millions)		
Deferred income tax charges	**$ 354**	$ 389	(a)
Loss on reacquired debt	**94**	102	(b)
DOE assessments	**-**	5	(c)
Vacation pay	**46**	45	(d)
Under recovered regulatory clause revenues	**334**	319	(e)
Fuel-hedging assets	**36**	9	(f)
Other assets	**6**	6	(e)
Asset retirement obligations	**(152)**	(139)	(a)
Other cost of removal obligations	**(600)**	(600)	(a)
Deferred income tax credits	**(99)**	(102)	(a)
Natural disaster reserve (prior storms)	**17**	51	(e)
Fuel-hedging liabilities	**(3)**	(38)	(f)
Mine reclamation and remediation	**(16)**	(16)	(e)
Nuclear outage	**(12)**	(8)	(e)
Deferred purchased power	**(19)**	(19)	(e)
Natural disaster reserve (future storms)	**(13)**	-	(e)
Other liabilities	**(3)**	(3)	(e)
Overfunded retiree benefit plans	**(183)**	-	(g)
Underfunded retiree benefit plans	**183**	-	(g)
Total	**$ (30)**	$ 1	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue which may range up to 50 years.

(c) Assessments for the decontamination and decommissioning of the DOE nuclear fuel enrichment facilities are recorded annually from 1993 through 2006.

(d) Recorded as earned by employees and recovered as paid, generally within one year.

(e) Recorded and recovered or amortized as approved or accepted by the Alabama PSC.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clauses.

(g) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under "Retirement Benefits."

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 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, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates.

Nuclear Fuel Disposal Costs

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 nuclear fuel in 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract. An on-site dry spent fuel storage facility at Plant Farley is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Also, the Energy Policy Act of 1992 established a Uranium Enrichment Decontamination and Decommissioning Fund, which has been funded in part by a special assessment on utilities with nuclear plants. This assessment was paid over a 15-year period; the final installment occurred in 2006. 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.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also 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 totaled $66 million in 2006, $64 million in 2005, and $61 million in 2004.

Income and Other 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 life of the related property.

Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Property, Plant, and Equipment

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

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2006	2005
Generation	**$ 8,312**	$ 7,971
Transmission	**2,308**	2,205
Distribution	**4,352**	4,115
General	**1,017**	1,000
Plant acquisition adjustment	**9**	9
Total plant in service	**$15,998**	$15,300

The cost of replacements of property – exclusive of minor items of property – is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. The Company accrues estimated nuclear refueling costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2006, the Company accrued $31.5 million and paid $26.7 million for an outage at Unit 1. At December 31, 2006, the reserve balance totaled $12.3 million and is included in the balance sheet in other regulatory liabilities.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.1 percent in 2006, 2.9 percent in 2005, and 3.0 percent in 2004. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs of an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2006 was $513 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of $35 million, related to asbestos removal and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2006	2005
	(in millions)	
Balance beginning of year	$446	$384
Liabilities incurred	3	36
Liabilities settled	(3)	-
Accretion	30	26
Cash flow revisions	-	-
Balance end of year	$476	$446

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale.

The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. As the external trust funds are actively managed by unrelated parties with limited direction from the Company, the Company does not have the ability to choose to hold securities with unrealized losses until recovery. Through 2005, the Company considered other-than-temporary impairments to be immaterial. However, since the January 1, 2006 effective date of FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" (FSP No. 115-1), the Company considers all unrealized losses to represent other-than-temporary impairments. The adoption of FSP No. 115-1 had no impact on the results of operations, cash flows, or financial condition of the Company as all losses have been and continue to be recorded through a regulatory liability, whether realized, unrealized, or identified as other-than-temporary. Details of the securities held in these trusts at December 31 are as follows:

2006	Unrealized Gains	Other-than-Temporary Impairments	Fair Value
		(in millions)	
Equity	$121.0	$(5.3)	$384.8
Debt	0.7	(1.4)	120.1
Other	-	-	8.6
Total	$121.7	$(6.7)	$513.5

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$78.9	$(7.7)	$275.3
Debt	1.3	(1.6)	106.1
Other	17.0	-	85.6
Total	$97.2	$(9.3)	$467.0

The contractual maturities of debt securities at December 31, 2006 are as follows: $1.2 million in 2007; $29.5 million in 2008-2011; $43.2 million in 2012-2016; and $45.1 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $285.7 million, $223.8 million, and $249.0 million in 2006, 2005, and 2004, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were $22.0 million and $18.2 million, respectively, in 2006. Net realized gains were $9.9 million and $7.5 million in 2005 and 2004, respectively. Realized gains and other-than-temporary impairment losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and other-than-temporary impairment losses are considered non-cash transactions for purposes of the statements of cash flow.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. At December 31, 2006, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds, at fair value	$513
Internal reserves	28
Total	$541

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning, based on the most current study performed in 2003 for Plant Farley were as follows:

Decommissioning periods:	
Beginning year	2017
Completion year	2046
	(in millions)
Site study costs:	
Radiated structures	$892
Non-radiated structures	63
Total	$955

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

All of the Company's decommissioning costs for ratemaking are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5 percent and a trust earnings rate of 7.0 percent. Another significant assumption used was the change in the operating license for Plant Farley.

In May 2005, the NRC granted the Company a 20-year extension of the operating license for both units at Plant Farley. As a result of the license extension, amounts previously contributed to the external trust are currently projected to be adequate to meet the decommissioning obligations. Therefore, in June 2005, the Alabama PSC approved the Company's request to suspend, effective January 1, 2005, the inclusion in its annual cost of service of $18 million in decommissioning costs and to also suspend the associated obligation to make semi-annual contributions to the external trust. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements. The approved suspension does not affect the transfer of internal reserves (less than $1 million annually) previously collected from customers prior to the establishment of the external trust.

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 8.8 percent in 2006, 8.8 percent in 2005, and 8.6 percent in 2004. AFUDC, net of income tax, as a percent of net income after dividends on preferred stock was 4.5 percent in 2006, 5.0 percent in 2005, and 4.2 percent in 2004.

Impairment of Long-Lived Assets and Intangibles

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

Natural Disaster Reserve

In accordance with an Alabama PSC order, the Company has established a natural disaster reserve (NDR) to cover the cost of uninsured damages from major storms to transmission and distribution facilities. The Company collects a monthly NDR charge per account that consists of two components which began on January 1, 2006. The first component is intended to establish and maintain a reserve for future storms and is an on-going part of customer billing. This plan has a target reserve balance of $75 million that could be achieved in five years assuming the Company experiences no additional storms. The second component of the NDR charge is intended to allow recovery of the deferred Hurricanes Dennis- and Katrina-related operations and maintenance costs and to set in place a mechanism to replenish the NDR should any future storms deplete the natural disaster reserve. The Alabama PSC order gives the Company authority to have a negative NDR balance when costs of uninsured storm damage exceed any established NDR balance. This second component allows for the recovery of a negative balance over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per account for non-residential customers and $5 per month per account for residential customers.

At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." Also the Company has recovered $33.8 million of deferred Hurricanes Dennis- and Katrina-related operations and maintenance costs and the deficit balance in the NDR account as of December 31, 2006 totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm-related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of the NDR charge.

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

Environmental Cost Recovery

The Company has received authority from the Alabama PSC to recover approved environmental compliance costs through specific retail rate clauses and are adjusted annually. See Note 3 under "Retail Regulatory Matters – Rate CNP" for additional information.

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 average 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, and natural gas. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Alabama PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. Prior to January 1, 2006, the Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as at January 1, 2006, for which the requisite service has not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

For the Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings before income taxes and net income of $4.8 million and $3.0 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $1.3 million.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact on net income of fair-value accounting for options granted is as follows:

Net Income	As Reported	Options Impact After Tax	Pro Forma
		(in thousands)	
2005	$507,895	$(2,829)	$505,066
2004	481,171	(2,575)	478,596

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	2006	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant-date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC approved fuel-hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2006	**$4,816**	**$4,768**
2005	4,416	4,403

The fair values were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in additional minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts in the balance sheets.

Investments

The Company maintains an investment in a debt security that matures in 2018 and is classified as available-for-sale. This security is included in the balance sheets under Other Property and Investments-Other and totaled $2.6 million and $4.4 million at December 31, 2006 and 2005, respectively. Because the interest rate resets weekly, the carrying value approximates the fair market value.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides certain defined benefit pension plans for a selected group of management and highly-compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds trusts to the extent required by the Alabama PSC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $24.7 million.

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, the Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to its underfunded non-qualified pension plan, the Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

With the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet previously unrecognized assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $183 million with respect to its overfunded defined benefit plan and additional liabilities of $10 million and $147 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. The incremental effect of applying

SFAS No. 158 on individual line items in the balance sheet at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension costs	$ 539	$ 183	$ 722
Other regulatory assets	97	183	280
Other property and investments	603	(6)	597
Total assets	14,295	360	14,655
Accumulated deferred income taxes	(2,110)	(7)	(2,117)
Other regulatory liabilities	(217)	(183)	(400)
Employee benefit obligations	(219)	(157)	(376)
Total liabilities	(9,664)	(347)	(10,011)
Accumulated other comprehensive income	16	(13)	3
Total shareholders' equity	(4,631)	(13)	(4,644)

Because the recovery of postretirement benefit expense through rates is considered probable, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71 with respect to the prepaid assets and the liabilities.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, the Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The accumulated benefit obligation for the pension plans was $1.3 billion in 2006 and $1.3 billion in 2005.

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

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$1,421	$1,325
Service cost	37	33
Interest cost	76	74
Benefits paid	(69)	(65)
Plan amendments	2	8
Actuarial (gain) loss	(73)	46
Balance at end of year	1,394	1,421
Change in plan assets		
Fair value of plan assets at beginning of year	1,875	1,676
Actual return on plan assets	232	262
Employer contributions	4	4
Benefits paid	(69)	(65)
Employee transfers	(4)	(2)
Fair value of plan assets at end of year	2,038	1,875
Funded status at end of year	644	454
Unrecognized prior service cost	-	79
Unrecognized net (gain)	-	(54)
Fourth quarter contributions	1	2
Prepaid pension asset, net	$ 645	$ 481

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $1.3 billion and $79 million, respectively. All plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the

Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	**38%**	40%
International equity	24	**23**	24
Fixed income	15	**16**	17
Real estate	15	**16**	13
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of:

	2006	2005
	(in millions)	
Prepaid pension asset	**$ 722**	$515
Other regulatory assets	**36**	-
Current liabilities, other	**(5)**	-
Other regulatory liabilities	**(183)**	-
Employee benefit obligations	**(72)**	(67)
Other property and investments	**-**	10
Accumulated other comprehensive income	**-**	23

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year:

	Prior Service Cost	Net (Gain)/ Loss
	(in millions)	
Balance at December 31, 2006:		
Regulatory asset	$ 6	$ 30
Regulatory liability	64	(247)
Total	$70	$(217)
Estimated amortization in net periodic pension cost in 2007:		
Regulatory asset	$1	$3
Regulatory liability	8	-
Total	$9	$3

Components of net periodic pension cost (income) were as follows:

	2006	2005	2004
	(in millions)		
Service cost	**$ 37**	$ 33	$ 30
Interest cost	**77**	74	71
Expected return on plan assets	**(139)**	(139)	(138)
Recognized net (gain) loss	**3**	2	(3)
Net amortization	**9**	9	4
Net periodic pension (income)	**$ (13)**	$ (21)	$ (36)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2007	$ 69
2008	71
2009	73
2010	77
2011	80
2012 to 2016	467

Other Postretirement Benefits

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

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 490**	$ 465
Service cost	**7**	7
Interest cost	**26**	26
Benefits paid	**(22)**	(21)
Actuarial (gain) loss	**(13)**	13
Retiree drug subsidy	**2**	-
Balance at end of year	**490**	490
Change in plan assets		
Fair value of plan assets at beginning of year	**245**	212
Actual return on plan assets	**23**	28
Employer contributions	**27**	26
Benefits paid	**(36)**	(21)
Fair value of plan assets at end of year	**259**	245
Funded status at end of year	**(231)**	(245)
Unrecognized transition amount	**-**	29
Unrecognized prior service cost	**-**	64
Unrecognized net loss	**-**	85
Fourth quarter contributions	**26**	12
Accrued liability (recognized in the balance sheet)	**$(205)**	$ (55)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	45%	**46%**	53%
International equity	15	**16**	11
Fixed income	29	**28**	28
Real estate	7	**7**	6
Private equity	4	**3**	2
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of:

	2006	2005
	(in millions)	
Regulatory assets	**$ 147**	$ -
Employee benefit obligations	**(205)**	(55)

Presented below are the amounts included in regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2006:			
Regulatory asset	$59	$63	$25
Estimated amortization as net periodic postretirement cost in 2007:			
Regulatory asset	$ 5	$ 2	$ 4

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

	2006	2005	2004
		(in millions)	
Service cost	**$ 7**	$ 7	$ 7
Interest cost	**26**	26	24
Expected return on plan assets	**(17)**	(16)	(18)
Net amortization	**12**	11	9
Net postretirement cost	**$ 28**	$ 28	$ 22

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2), related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plans. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $3.2 million, $8.7 million, and $11.1 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2007	$ 23	$ (2)	$ 21
2008	25	(2)	23
2009	27	(3)	24
2010	30	(3)	27
2011	32	(4)	28
2012 to 2016	181	(26)	155

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015, 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$36	$31
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 an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $14 million, $14 million, and $13 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama, after it was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required the Company to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by the Company, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit, and on November 14, 2006, the Eleventh Circuit granted the plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $3.9 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $14.6 million for the Company, of which $3.1 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the Company, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11 million previously paid for interconnection facilities, with interest. The Company has also received requests for similar modifications from other entities totaling approximately $7 million, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Retail Regulatory Matters

The following retail ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

Rate RSE

The Alabama PSC has adopted a Rate Stabilization and Equalization plan (Rate RSE) that provides for periodic annual adjustments based upon the Company's earned return on retail common equity. Prior to January 2007, annual adjustments were limited to 3 percent. Rates remain unchanged when the return on common equity ranges between 13.0 percent and 14.5 percent. On October 4, 2005, the Alabama PSC approved a revision to Rate RSE. Effective January 2007 and thereafter, Rate RSE adjustments are made based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0 percent per year and any annual adjustment is limited to 5.0 percent. The range of return on common equity, on which such adjustments are based, remains unchanged. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual return on common equity fall below the allowed equity return range. The Company made its initial submission of projected data for calendar year 2007 on December 1, 2006. The Rate RSE increase for 2007, effective in January, is 4.76 percent, or $193 million annually. Under the terms of Rate RSE, the maximum increase for 2008 cannot exceed 3.24 percent. See "Rate CNP" for additional information.

Rate CNP

The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the placing of new generating facilities in retail service and for the recovery of retail costs associated with certificated purchased power agreements (Rate CNP). In October 2004, the Alabama PSC approved a request by the Company to amend Rate CNP to provide for the recovery of retail costs associated with environmental laws and regulations. Environmental costs to be recovered include operation and maintenance expenses, depreciation and a return on invested capital. This component of Rate CNP began operation in January 2005.

To recover certificated purchased power costs under Rate CNP, increases of 0.8 percent in retail rates, or $25 million annually were effective July 2004. In April 2005, an adjustment to Rate CNP decreased retail rates by approximately 0.5 percent, or $19 million annually. In April 2006, an annual true-up adjustment to Rate CNP increased retail rates by approximately 0.5 percent, or $19 million annually.

The retail rates to recover retail costs associated with environmental laws and regulations under Rate CNP are adjusted annually in January. Retail rates increased approximately 1.0 percent in 2005, or $33 million. In 2006, retail rates increased approximately 1.2 percent, or $43 million, and in 2007 retail rates increased approximately 0.6 percent, or $23 million.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. The Company can change the retail energy cost recovery rate after submitting to the Alabama PSC an estimate of future energy costs and the current over or under recovered balance. In response to such a request, the Alabama PSC may conduct a public hearing prior to its ruling. Alternatively, the retail energy cost recovery rates requested by the Company will become effective 45 days after the initial request.

In December 2005, the Alabama PSC approved the Company's request to increase the retail energy cost recovery rate to 2.400 cents per kilowatt-hour, effective with billings that began in January 2006 for the 24-month period ending December 31, 2007. Thereafter, the energy cost recovery rate factor will increase absent a contrary order by the Alabama PSC.

The Company's under recovered fuel costs as of December 31, 2006 is $301.0 million and is classified as deferred charges and other assets in the balance sheet as of December 31, 2006.

Natural Disaster Cost Recovery

In September 2004, Hurricane Ivan hit the Gulf Coast of Florida and Alabama and continued north through the Company's service territory causing substantial damage. The related costs charged to the Company's NDR were $57.8 million. During 2004, the Company accrued $9.9 million to the reserve and at December 31, 2004, the reserve balance was a regulatory asset of $37.7 million.

In February and December 2005, the Company requested and received Alabama PSC approval of an accounting order that allowed the Company to immediately return certain regulatory liabilities to the retail customers. These orders also allowed the Company to simultaneously recover from customers an accrual of approximately $48 million primarily to offset the costs of Hurricane Ivan and restore a positive balance in the NDR. The combined effect of these orders had no impact on the Company's net income in 2005.

On July 10, 2005 and August 29, 2005, Hurricanes Dennis and Katrina, respectively, hit the coast of Alabama and continued north through the state, causing significant damage in parts of the service territory of the Company. Approximately 241,000 and 637,000 of the Company's 1.4 million customer accounts were without electrical service immediately after Hurricanes Dennis and Katrina, respectively. The Company sustained significant damage to its distribution and transmission facilities during these storms.

In August 2005, the Company received approval from the Alabama PSC to defer the Hurricane Dennis storm-related operation and maintenance costs (approximately $28 million). In October 2005, the Company also received similar approval from the Alabama PSC to defer the Hurricane Katrina storm-related operation and maintenance costs (approximately $30 million). The NDR balance at December 31, 2005 was a regulatory asset of $50.6 million.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted NDR and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components which began in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The Company currently expects that the target reserve balance could be achieved within five years. The second component of the NDR charge is intended to allow recovery of the existing deferred hurricane related operation and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

As of December 31, 2006, the Company had recovered $49.5 million of the costs allowed for storm-recovery activities and the deficit balance in the NDR account totaled approximately $16.8 million, which is included in the balance sheets under "Current Assets." Absent any new storm-related damages, the Company expects to fully recover the deferred storm costs by the middle of 2007. As a result, customer rates would be decreased by this portion of NDR. At December 31, 2006, the Company had accumulated a balance of $13.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities."

As revenue from the NDR charge is recognized, an equal amount of operation and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as 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 purchased power totaled $95 million in 2006, $90 million in 2005, and $86 million in 2004 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

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. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations 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, 2006, the capitalization of SEGCO consisted of $60 million of equity and $88 million of debt on which the annual interest requirement is $3.2 million. SEGCO paid dividends totaling $8.5 million in 2006, $7.7 million in 2005, and $12.0 million in 2004, of which one-half of each was paid to the Company. In addition, the Company recognizes 50 percent of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2006 is as follows:

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

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

Facility	Company Investment	Accumulated Depreciation
	(In millions)	
Greene County	$118	$ 65
Plant Miller		
Units 1 and 2	958	396

At December 31, 2006, the Company's Plant Miller portion of construction work in progress was $14.9 million.

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

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the State of Georgia and the State of Alabama. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

In 2004 and 2005, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. At December 31, 2006 and 2005, the Company had $34.9 million and $20.4 million in accumulated deferred income taxes and $3.1 million and $2.0 million in accrued taxes – income taxes, respectively, payable to these subsidiaries, on the balance sheets.

At December 31, 2006, the Company's tax-related regulatory assets and liabilities were $354 million and $99 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 the current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2006	2005	2004
	(in millions)		
Federal --			
Current	**$302**	$151	$ 44
Deferred	**(25)**	81	219
	277	232	263
State --			
Current	**56**	27	16
Deferred	**(3)**	26	34
	53	53	50
Total	**$330**	$285	$313

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:

	2006	2005
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,651**	$1,626
Property basis differences	**377**	426
Premium on reacquired debt	**39**	42
Pension and other benefits	**224**	148
Fuel clause under recovered	**137**	138
Regulatory assets associated with employee benefit obligations	**102**	-
Regulatory assets associated with asset retirement obligations	**200**	186
Storm reserve	**10**	26
Other	**57**	47
Total	**2,797**	2,639
Deferred tax assets:		
Federal effect of state deferred taxes	**118**	114
State effect of federal deferred taxes	**62**	87
Unbilled revenue	**25**	22
Pension and other benefits	**133**	20
Other comprehensive losses	**10**	19
Regulatory liabilities associated with employee benefit obligations	**71**	-
Asset retirement obligations	**200**	186
Other	**83**	56
Total	**702**	504
Total deferred tax liabilities, net	**2,095**	2,135
Portion included in current (liabilities) assets, net	**22**	(64)
Accumulated deferred income taxes in the balance sheets	**$2,117**	$2,071

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8.0 million in 2006, $8.8 million in 2005, and $11.0 million in 2004. At December 31, 2006, 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:

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.0**	4.2	4.0
Non-deductible book depreciation	**1.0**	1.1	1.1
Differences in prior years' deferred and current tax rates	**(0.3)**	(4.1)	(0.8)
Other	**(1.8)**	(1.3)	(1.0)
Effective income tax rate	**37.9%**	34.9%	38.3%

In accordance with Alabama PSC orders, the Company returned approximately $30 million of excess deferred income taxes to its ratepayers in 2005, resulting in 3.6 percent of the "Difference in prior years' deferred and current tax rates" in the table above. See Note 3 to the financial statements under "Retail Regulatory Matters – Natural Disaster Cost Recovery" for additional information.

6. FINANCING

Mandatorily Redeemable Preferred Securities/ Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $309 million, which constitute substantially all assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2006, preferred securities of $300 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

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.

Senior Notes

The Company issued a total of $950 million of unsecured senior notes in 2006. The proceeds of these issuances were used to repay short-term indebtedness, and for other general corporate purposes.

At December 31, 2006 and 2005, the Company had $4.0 billion and $3.6 billion of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2006.

On February 6, 2007, the Company issued $200 million of long-term senior notes. The proceeds were used to repay short-term indebtedness and for other general corporate purposes.

Preference and Common Stock

In 2006, the Company issued six million new shares of preference stock at $25.00 stated capital per share and realized proceeds of $150 million. In addition, the Company issued three million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $120 million. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock, Class A preferred stock, and preference stock are subject to redemption at the option of the Company on or after a specified date.

Securities Due Within One Year

At December 31, 2006 and 2005, the Company had scheduled maturities and redemptions of senior notes due within one year totaling $669 million and $547 million, respectively.

Debt maturities through 2011 applicable to total long-term debt are as follows: $669 million in 2007; $410 million in 2008; $250 million in 2009; $100 million in 2010; and $200 million in 2011.

Assets Subject to Lien

At January 1, 2006, the Company had a mortgage that secured first mortgage bonds they had issued and constituted a direct first lien on substantially all of its fixed property and franchises. In 2006, the Company discharged its remaining outstanding first mortgage bond obligations and the lien was removed in May 2006. The Company has granted liens on certain property in connection with the issuance of certain series of pollution control bonds with an outstanding principal amount of $153 million.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $965 million (including $563 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control bonds), of which $365 million will expire at various times during 2007. $198 million of the credit facilities expiring in 2007 allow for the execution of one-year term loans. The remaining $600 million of credit facilities expire in 2011. All of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees are less than 1/4 of 1 percent for the Company. The Company does not consider any of its cash balances to be restricted as of any specific date.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65 percent of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2006, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through extendible commercial note programs and uncommitted credit arrangements. As of December 31, 2006, the Company had $120 million in commercial paper outstanding and no extendible commercial notes outstanding. As of December 31, 2005, the Company had $136 million in commercial paper outstanding, $55 million in extendible commercial notes outstanding, and $125 million in loans outstanding under an uncommitted credit arrangement. During 2006 and 2005, the peak amount outstanding for short-term borrowings was $411 million and $315 million, respectively. The average amount outstanding in 2006 and 2005 was $45 million and $31 million, respectively. The average annual interest rate on short-term borrowings in 2006 was 4.76 percent and in 2005 was 4.04 percent. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2006, the Company had regulatory approval to have outstanding up to $1.4 billion of short-term borrowings.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs at the instruction of the Alabama PSC. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, and 2004.

At December 31, 2006, the fair value gains/(losses) of derivative energy contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$(33,267)
Accumulated other comprehensive income	676
Net income	(37)
Total fair value	$(32,628)

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in the regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2009.

The Company also enters into derivatives to hedge exposure to changes in interest rates. Derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings.

At December 31, 2006, the Company had $736 million notional amount of interest rate derivatives outstanding with net fair value loss of $3.0 million as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/ (Loss)
		(in millions)	
2007***	2.01*	$536	$ 0.8
2017	6.15**	100	(1.9)
2017	6.15**	100	(1.9)

* Hedged using the Bond Market Association Municipal Swap Index.

** Interest rate collar (showing only the cap rate percentage).

*** Matured January 2007.

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2006, 2005, and 2004, the Company settled gains (losses) of $18.0 million, $(21.4) million, and $5.5 million, respectively, upon termination of certain interest derivatives at the same time it issued debt. These gains (losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative, which approximates to the related underlying debt.

For the years 2006, 2005, and 2004, approximately $9.8 million, $3.5 million, and $(6.3) million, respectively, of pre-tax gains (losses) were reclassified from other comprehensive income to interest expense. For 2007, pre-tax losses of approximately $0.1 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2017 and has gains (losses) that are being amortized through 2035.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $1.2 billion in 2007, $1.3 billion in 2008, and $1.3 billion in 2009. These amounts include $26 million, $35 million, and $34 million in 2007, 2008, and 2009, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental regulations; changes in existing nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

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

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $155 million over the remaining life of the agreements, which are currently estimated to range up to 10 years. However, the LTSAs contain various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2006 were as follows:

	Commitments		
Year	Affiliated	Non-Affiliated	Total
	(in millions)		
2007	$ 50	$ 38	$ 88
2008	50	39	89
2009	50	40	90
2010	12	23	35
2011	-	2	2
2012 and thereafter	-	-	-
Total commitments	$162	$142	$304

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. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006. Total estimated minimum long-term commitments at December 31, 2006 were as follows:

Year	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2007	$ 342	$1,094	$ 26
2008	281	683	35
2009	173	618	34
2010	84	603	39
2011	15	544	45
2012 and thereafter	123	2,145	67
Total commitments	$1,018	$5,687	$246

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $30.3 million in 2006, $27.3 million in 2005, and $28.3 million in 2004. Of these amounts, $21.5 million, $17.8 million, and $16.3 million for 2006, 2005, and 2004, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR. At December 31, 2006, estimated minimum rental commitments for noncancellable operating leases were as follows:

Year	Rail Cars	Vehicles & Other	Total
	(in millions)		
2007	$20.5	$ 7.6	$ 28.1
2008	19.7	6.4	26.1
2009	15.2	6.1	21.3
2010	10.4	5.7	16.1
2011	5.3	3.9	9.2
2012 and thereafter	22.9	3.0	25.9
Total minimum payments	$94.0	$32.7	$126.7

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2009 and 2010, and the Company's maximum obligations are $19.5 million and $62.3 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 eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2006, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2006, there were 1,108 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options that were used under SFAS No. 123.

The Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at Dec, 31, 2005	5,227,985	$27.09
Granted	1,150,870	33.81
Exercised	(474,451)	24.28
Cancelled	(9,275)	29.35
Outstanding at Dec. 31, 2006	**5,895,129**	**$28.63**
Exercisable at Dec. 31, 2006	**3,739,865**	**$26.26**

The number of stock options vested and expected to vest in the future, as of December 31, 2006 is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

As of December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.6 years and 5.5 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $48.5 million and $39.7 million, respectively.

As of December 31, 2006, there was $1.4 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $4.9 million, $21.9 million, and $16.1 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.9 million, $8.5 million, and $6.2 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (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 $10.8 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. The Company could be assessed up to $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 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 $201 million per incident but not more than an aggregate of $30 million to be paid for each incident in any one year.

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

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

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

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $38 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all "non-certified" terrorist acts, i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12 month duration, is $3.2 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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 information for 2006 and 2005 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2006	**$1,073**	**$198**	**$ 82**
June 2006	**1,249**	**258**	**118**
September 2006	**1,572**	**458**	**238**
December 2006	**1,121**	**196**	**80**
March 2005	$ 970	$157	$ 93
June 2005	1,086	253	122
September 2005	1,458	443	236
December 2005	1,134	161	57

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

SELECTED FINANCIAL AND OPERATING DATA 2002-2006

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	$ 5,014,728	$ 4,647,824	$ 4,235,991	$ 3,960,161	$ 3,710,533
Net Income after Dividends on Preferred and Preference Stock (in thousands)	$ 517,730	$ 507,895	$ 481,171	$ 472,810	$ 461,355
Cash Dividends on Common Stock (in thousands)	$ 440,600	$ 409,900	$ 437,300	$ 430,200	$ 431,000
Return on Average Common Equity (percent)	13.23	13.72	13.53	13.75	13.80
Total Assets (in thousands)	$14,655,290	$13,689,907	$12,781,525	$12,099,575	$11,591,666
Gross Property Additions (in thousands)	$ 960,759	$ 890,062	$ 786,298	$ 661,154	$ 645,262
Capitalization (in thousands):					
Common stock equity	$ 4,032,287	$ 3,792,726	$ 3,610,204	$ 3,500,660	$ 3,377,740
Preferred and preference stock	612,407	465,046	465,047	372,512	247,512
Mandatorily redeemable preferred securities	-	-	-	300,000	300,000
Long-term debt payable to affiliated trusts	309,279	309,279	309,279	-	-
Long-term debt	3,838,906	3,560,186	3,855,257	3,377,148	2,872,609
Total (excluding amounts due within one year)	$ 8,792,879	$ 8,127,237	$ 8,239,787	$ 7,550,320	$ 6,797,861
Capitalization Ratios (percent):					
Common stock equity	45.9	46.7	43.8	46.4	49.7
Preferred and preference stock	7.0	5.7	5.6	4.9	3.6
Mandatorily redeemable preferred securities	-	-	-	4.0	4.4
Long-term debt payable to affiliated trusts	3.5	3.8	3.8	-	-
Long-term debt	43.6	43.8	46.8	44.7	42.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	-	A1	A1	A1	A1
Standard and Poor's	-	A+	A	A	A
Fitch	-	AA-	AA-	A+	A+
Preferred Stock/ Preference Stock -					
Moody's	Baa1	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
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	1,194,696	1,184,406	1,170,814	1,160,129	1,148,645
Commercial	214,723	212,546	208,547	204,561	203,017
Industrial	5,750	5,492	5,260	5,032	4,874
Other	766	759	753	757	789
Total	1,415,935	1,403,203	1,385,374	1,370,479	1,357,325
Employees (year-end)	6,796	6,621	6,745	6,730	6,715

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	**$ 1,664,304**	$ 1,476,211	$ 1,346,669	$ 1,276,800	$ 1,264,431
Commercial	**1,172,436**	1,062,341	980,771	913,697	882,669
Industrial	**1,140,225**	1,065,124	948,528	844,538	788,037
Other	**18,766**	17,745	16,860	16,428	16,080
Total retail	**3,995,731**	3,621,421	3,292,828	3,051,463	2,951,217
Sales for resale - non-affiliates	**634,552**	551,408	483,839	487,456	474,291
Sales for resale - affiliates	**216,028**	288,956	308,312	277,287	188,163
Total revenues from sales of electricity	**4,846,311**	4,461,785	4,084,979	3,816,206	3,613,671
Other revenues	**168,417**	186,039	151,012	143,955	96,862
Total	**$ 5,014,728**	$ 4,647,824	$ 4,235,991	$ 3,960,161	$ 3,710,533
Kilowatt-Hour Sales (in thousands):					
Residential	**18,632,935**	18,073,783	17,368,321	16,959,566	17,402,645
Commercial	**14,355,091**	14,061,650	13,822,926	13,451,757	13,362,631
Industrial	**23,187,328**	23,349,769	22,854,399	21,593,519	21,102,568
Other	**199,445**	198,715	198,253	203,178	205,346
Total retail	**56,374,799**	55,683,917	54,243,899	52,208,020	52,073,190
Sales for resale - non-affiliates	**15,978,465**	15,442,728	15,483,420	17,085,376	15,553,545
Sales for resale - affiliates	**5,145,107**	5,735,429	7,233,880	9,422,301	8,844,050
Total	**77,498,371**	76,862,074	76,961,199	78,715,697	76,470,785
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.93**	8.17	7.75	7.53	7.27
Commercial	**8.17**	7.55	7.10	6.79	6.61
Industrial	**4.92**	4.56	4.15	3.91	3.73
Total retail	**7.09**	6.50	6.07	5.84	5.67
Sales for resale	**4.03**	3.97	3.49	2.88	2.72
Total sales	**6.25**	5.80	5.31	4.85	4.73
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,663**	15,347	14,894	14,688	15,198
Residential Average Annual Revenue Per Customer	**$ 1,399**	$ 1,253	$ 1,155	$ 1,106	$ 1,104
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,216	12,216	12,174	12,153
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,309**	9,812	9,556	10,409	9,423
Summer	**11,744**	11,162	10,938	10,462	10,910
Annual Load Factor (percent)	**61.8**	63.2	63.2	64.1	62.9
Plant Availability (percent):					
Fossil-steam	**89.6**	90.5	87.8	85.9	85.8
Nuclear	**93.3**	92.9	88.7	94.7	93.2
Source of Energy Supply (percent):					
Coal	**60.2**	59.5	56.5	56.5	55.5
Nuclear	**17.4**	17.2	16.4	17.0	17.1
Hydro	**3.8**	5.6	5.6	7.0	5.1
Gas	**7.6**	6.8	8.9	7.6	11.6
Purchased power -					
From non-affiliates	**2.1**	3.8	5.4	4.1	4.0
From affiliates	**8.9**	7.1	7.2	7.8	6.7
Total	**100.0**	100.0	100.0	100.0	100.0

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GEORGIA POWER COMPANY

FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-160 to II-191) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 Georgia Power Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Effective July 1, 2006, Savannah Electric and Power Company (Savannah Electric), which was also a wholly owned subsidiary of Southern Company, was merged into the Company. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements included herein now reflect the merger as though it had occurred on January 1, 2004. The supplemental selected financial and operating data reflect the merger as though it had occurred on January 1, 2002. See FUTURE EARNINGS POTENTIAL – "Merger" and Note 3 to the financial statements under "Retail Regulatory Matters – Merger" for additional information.

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, and fuel prices. In December 2004, the Company completed a major retail rate proceeding (2004 Retail Rate Plan) that has provided earnings stability. This regulatory action also enabled the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution network and continued environmental improvements at the generating plants. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a general rate case by July 1, 2007, which will determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. The Company also received regulatory orders to increase its fuel cost recovery rate effective June 1, 2005, July 1, 2006, and March 1, 2007.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2006 Peak Season EFOR of 0.99 percent is above target, a significant improvement over 2005 Peak Season EFOR of 1.42 percent. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. 2006 performance exceeded all targets on these reliability measures. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2006 results compared to its targets for some of these indicators are reflected in the following chart.

Key Performance Indicator	2006 Target Performance	**2006 Actual Performance**
Customer Satisfaction	Top quartile in customer surveys	**Top quartile in customer surveys**
Peak Season EFOR	2.75% or less	**0.99%**
Net Income	$770 million	**$787 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2006 net income after dividends on preferred stock totaled $787 million representing a

$43 million, or 5.8 percent, increase over 2005. Operating income increased in 2006 due to higher base retail revenues and wholesale non-fuel revenues, partially offset by higher non-fuel operating expenses and higher financing costs. The Company's 2005 earnings totaled $744 million representing a $61 million, or 9.0 percent, increase over 2004. Operating income increased in 2005 due to higher base retail revenues resulting from retail rate increases effective January 1, 2005 and June 1, 2005 and more favorable weather, as well as higher wholesale revenues resulting from new contracts effective January 1, 2005, partially offset by increased non-fuel operating expenses. The Company's 2004 earnings totaled $683 million representing a $29 million, or 4.4 percent, increase over 2003. Operating income increased in 2004 due to higher base retail revenues attributable to more favorable weather and customer growth during the year, partially offset by higher non-fuel operating expenses. In addition, lower depreciation and amortization expense resulting from a three-year retail rate plan approved by the Georgia Public Service Commission (PSC) in 2001 (2001 Retail Rate Plan) significantly offset increased purchased power capacity expenses.

RESULTS OF OPERATIONS

A condensed income statement for the Company is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
		(in millions)		
Operating revenues	**$7,246**	**$ 170**	$1,348	$499
Fuel	**2,233**	**296**	649	129
Purchased power	**1,145**	**(171)**	215	237
Other operations and maintenance	**1,560**	**(11)**	86	154
Depreciation and amortization	**499**	**(28)**	230	(74)
Taxes other than income taxes	**299**	**23**	33	16
Total operating expenses	**5,736**	**109**	1,213	462
Operating income	**1,510**	**61**	135	37
Total other income and (expense)	**(276)**	**(22)**	(19)	5
Income taxes	**442**	**(5)**	54	12
Net income	**792**	**44**	62	30
Dividends on preferred stock	**5**	**1**	1	1
Net income after dividends on preferred stock	**$ 787**	**$ 43**	$ 61	$ 29

Revenues

Operating revenues in 2006, 2005, and 2004 and the percent of change from the prior year are as follows:

	Amount		
	2006	2005	2004
	(in millions)		
Retail – prior year	**$6,065**	$5,119	$4,609
Change in –			
Base rates	**3**	201	-
Sales growth	**(4)**	136	161
Weather	**7**	23	32
Fuel cost recovery	**134**	586	317
Retail – current year	**6,205**	6,065	5,119
Sales for resale –			
Non-affiliates	**552**	525	252
Affiliates	**253**	275	172
Total sales for resale	**805**	800	424
Other operating revenues	**236**	211	185
Total operating revenues	**$7,246**	$7,076	$5,728
Percent change	**2.4%**	23.5%	9.5%

Retail base revenues of $3.8 billion in 2006 increased $7.0 million, or 0.2 percent, from 2005 primarily due to customer growth of 1.9 percent and more favorable weather, partially offset by lower market-driven rates to large commercial and industrial customers. Retail base revenues of $3.8 billion in 2005 increased by $360 million, or 10.6 percent, from 2004 primarily due to the retail rate increases effective January 1, 2005 and June 1, 2005, sustained economic strength, customer growth, more favorable weather, and generally higher prices to large business customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information. Retail base revenues of $3.4 billion in 2004 increased by $192 million, or 6.0 percent, from 2003 primarily due to an improved economy, customer growth, generally higher prices to the Company's large business customers, and more favorable weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were:

	2006	2005	2004
	(in millions)		
Unit power sales --			
Capacity	**$ 33**	$ 33	$ 31
Energy	**38**	32	34
Other power sales --			
Capacity and other	**165**	155	75
Energy	**316**	305	112
Total	**$552**	$525	$252

Revenues from unit power sales contracts remained relatively constant in 2006, 2005, and 2004. Revenues from other non-affiliated sales increased $21 million, or 4.6 percent, and $273 million, or 146.0 percent, in 2006 and 2005, respectively, and decreased $13 million, or 6.5 percent, in 2004. The increase in 2006 was due to a 9.5 percent increase in the demand for kilowatt-hour (KWH) energy sales due to a new contract with an electrical membership corporation (EMC) that went into effect in April 2006. The increase in 2005 was primarily due to contracts with 30 EMCs that went into effect in January 2005 which increased the demand for energy. The capacity component of these transactions increased $1 million and $73.2 million in 2006 and 2005, respectively.

Revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2006 and 2005, KWH energy sales to affiliates increased 9.2 percent and 2.2 percent, respectively, due to higher demand. However, revenues from these sales decreased by 8.3 percent in 2006 due to reduced cost per KWH delivered. Revenues increased 59.8 percent in 2005 due to higher fuel prices. In 2004, KWH energy sales to affiliates decreased 18.3 percent due to lower demand. However, the decline in associated revenues was only 5.0 percent due to higher fuel prices. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $24.6 million, or 11.6 percent, in 2006 primarily due to increased revenues of $14.1 million related to work performed for the other owners of the integrated transmission system (ITS) in the State of Georgia, higher customer fees of $4.6 million, and higher outdoor lighting revenues of $6.1 million due to a 5.5 percent increase in customers. Other operating revenues increased $26.1 million, or 14.1 percent, in 2005 from 2004, primarily due to higher transmission revenues of $16 million related to work performed for the other owners of the ITS, higher revenues under the open access tariff agreement, higher outdoor lighting revenues of $5.4 million, and higher customer fees that went into effect in 2005 of $5.9 million. The increased transmission revenues in 2006 and 2005 did not have an impact on earnings since they were offset by associated transmission expenses. Other operating revenues increased $11.6 million, or 6.7 percent, in 2004 over 2003 primarily due to higher revenues from outdoor lighting of $4.2 million and pole attachment rentals of $4.9 million and higher gains on sales of emission allowances of $2 million.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. KWH sales for 2006 and the percent change by year were as follows:

	KWH	Percent Change		
	2006	**2006**	2005	2004
	(in billions)			
Residential	**26.2**	**2.7%**	2.7%	5.5%
Commercial	**32.1**	**2.5**	6.0	4.1
Industrial	**25.6**	**(1.0)**	(5.0)	2.4
Other	**0.7**	**(10.5)**	(1.0)	1.6
Total retail	**84.6**	**1.4**	1.3	3.9
Sales for resale				
Non-affiliates	**12.3**	**8.8**	85.5	(32.2)
Affiliates	**5.5**	**9.2**	2.2	(18.3)
Total sales for resale	**17.8**	**8.9**	48.3	(26.6)
Total sales	**102.4**	**2.6**	6.9	(1.0)

Residential KWH sales increased 2.7 percent in 2006 over 2005 due to customer growth of 1.9 percent and more favorable weather. Commercial KWH sales increased 2.5 percent in 2006 over 2005 due to customer growth of 2.0 percent and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC. Industrial KWH sales decreased 1.0 percent due to a 3.4 percent decrease in the number of customers as a result of this reclassification.

Residential KWH sales increased 2.7 percent in 2005 over 2004 due to more favorable weather, customer growth of 1.8 percent, and a 0.9 percent increase in the average energy consumption per customer. Commercial KWH sales increased 6.0 percent in 2005 when compared to 2004 due to more favorable weather, sustained economic strength, customer growth of 1.9 percent, and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia PSC. Industrial sales decreased 5.0 percent primarily due to this reclassification of customers.

Residential KWH sales increased 5.5 percent in 2004 from 2003 due to more favorable weather and a 1.9 percent increase in residential customers. Commercial KWH sales increased 4.1 percent in 2004 due to an improved economy and a 3.0 percent increase in commercial customers. Industrial sales increased 2.4 percent in 2004 due to the improved economy.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Details of the Company's generation, fuel, and purchased power are as follows:

	2006	2005	2004
Total generation (billions of KWH)	**83.7**	82.7	73.6
Total purchased power (billions of KWH)	**23.7**	21.7	24.5
Sources of generation (percent)			
Coal	**74.4**	75.7	76.0
Nuclear	**18.2**	18.2	21.8
Gas	**6.2**	3.8	0.3
Hydro	**1.2**	2.3	1.9
Cost of fuel, generated (cents per net KWH)			
Coal	**2.58**	1.91	1.89
Nuclear	**0.47**	0.47	0.46
Gas	**5.76**	14.03	8.04
Average cost of fuel, generated (cents per net KWH)	**2.39**	2.12	1.58
Average cost of purchased power (cents per net KWH)	**5.90**	7.10	5.09

Fuel and purchased power expenses were $3.4 billion in 2006, an increase of $124 million, or 3.8 percent, above prior year costs. This increase was driven by a $181 million increase related to total KWH generated and purchased, partially offset by a $57 million decrease in the cost of fuel.

Fuel and purchased power expenses were $3.3 billion in 2005, an increase of $863 million, or 36.1 percent, above prior year costs. This increase was the result of an

$868 million increase in the cost of fuel and a $5 million decrease related to total KWH generated and purchased.

Fuel and purchased power expenses were $2.4 billion in 2004, an increase of $365 million, or 18 percent, above prior year costs. This increase was the result of a $20 million increase in the cost of fuel and a $345 million increase related to total KWH generated and purchased.

The Company has entered into three power purchase agreements (PPAs) to purchase a total of approximately 1,000 megawatts (MW) annually from June 2009 through May 2024. These agreements were approved by the Georgia PSC on October 2, 2006. These agreements satisfy approximately 550 MW of growth, replace an existing 450 MW agreement that expires in May 2009, and are expected to result in higher operations and maintenance expenses that will be subject to recovery through future base rates.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL — "PSC MATTERS — Fuel Cost Recovery."

Other Operations and Maintenance Expenses

In 2006, other operations and maintenance expenses decreased $11 million, or 0.7 percent, from the prior year. Maintenance for generating plants decreased $20.0 million in 2006 as a result of scheduled outages in 2005 offset by an increase of $18.2 million for transmission and distribution expenses related to load dispatching and overhead line maintenance. Also contributing to the decrease were decreased employee benefit expenses related to medical benefits and lower workers compensation expense of $23.2 million, partially offset by lower pension income of $13.7 million.

In 2005, other operations and maintenance expenses increased $86 million, or 5.8 percent. Maintenance for generating plant and transmission and distribution increased $27.5 million and $15.9 million, respectively, as a result of scheduled outages and, to a lesser extent, certain flexible projects planned for other periods. Increased employee benefit expense of $18.9 million related to pension and medical benefits and higher property insurance costs of $4.6 million resulting from storm damage also contributed to the increase. Customer assistance expense and uncollectible account expense also increased an additional $9.3 million in 2005 over 2004, primarily as a result of promotional expenses related to an energy efficiency program and an increased number of customer bankruptcies.

In 2004, other operations and maintenance expenses increased $155 million, or 11.6 percent, in part due to the timing of generating plant maintenance of $37.6 million and transmission and distribution maintenance of $39.6 million. Increased employee benefit expense of $30 million related to pension and medical benefits and higher workers compensation expense of $8 million also contributed to the increase.

Depreciation and Amortization Expenses

Depreciation and amortization decreased $27.9 million, or 5.3 percent, in 2006 from the prior year due to the amortization of a regulatory liability related to the inclusion of certified PPAs in retail rates as ordered by the Georgia PSC under the terms of the 2004 Retail Rate Plan. This decrease was partially offset by a $15.9 million, or 3.2 percent, increase in depreciation expense in 2006 over 2005 due to an increase in plant in service. Depreciation and amortization increased $230 million, or 77.5 percent, in 2005 over 2004 primarily due to the expiration at the end of 2004 of certain provisions of the 2001 Retail Rate Plan. In accordance with the 2001 Retail Rate Plan, the Company amortized an accelerated cost recovery liability as a credit to amortization expense and recognized new Georgia PSC-certified purchased power costs in rates evenly over the three years ended December 31, 2004. This treatment resulted in a credit to amortization expense of $187.1 million in 2004 and a total decrease in depreciation and amortization of $74 million in 2004. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $22.8 million, or 8.3 percent, in 2006 primarily due to higher property taxes of $13.3 million as a result of an increase in property values and higher municipal gross receipts taxes of $9.1 million as a result of increased retail operating revenues. Taxes other than income taxes increased $33 million, or 13.6 percent, in 2005 primarily due to higher municipal gross receipts taxes of $18.1 million resulting from increased retail operating revenues and higher property taxes of $14.0 million. Taxes other than income taxes increased $15.6 million, or 6.8 percent, in 2004 primarily due to higher municipal gross receipts taxes associated with increased retail operating revenues.

Allowance For Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) remained relatively constant in 2006 and 2005 and increased $18.1 million in 2004, primarily due to the construction of the Plant McIntosh combined cycle units 10 and 11 which were placed in service in June 2005.

Interest Income

Interest income decreased $4.1 million in 2006 primarily due to interest on a favorable state tax settlement of $3.8 million in 2005. Interest income remained relatively constant in 2005. Interest income decreased $9 million in 2004 when compared to the prior year primarily due to interest on a favorable income tax settlement of $14.5 million in 2003.

Interest Expense

Interest expense increased $22.5 million, or 9.5 percent, in 2006 primarily due to generally higher interest rates on variable rate debt and commercial paper, the issuance of additional senior notes during 2005, and higher average balances on short-term debt. Interest expense increased $40.6 million, or 15.9 percent, in 2005 from 2004 primarily due to the issuance of additional senior notes in 2005 and generally higher interest rates on variable rate debt and commercial paper. Variable rates on pollution control bonds are highly correlated with the Bond Market Association Municipal Swap Index, which averaged 2.5 percent in 2005 and 1.2 percent in 2004. Variable rates on commercial paper and senior notes are highly correlated with the one-month London Interbank Offer Rate, which averaged 3.4 percent in 2005 and 1.5 percent in 2004. Interest expense remained relatively constant in 2004. The Company refinanced or retired $324 million, $635 million, and $470 million of securities in 2006, 2005, and 2004, respectively. Interest capitalized increased in 2005 and 2004 due to the Plant McIntosh construction referenced above.

Other Income and (Expense), net

Other income and (expense), net increased $1.9 million, or 26.7 percent, in 2006 primarily due to reduced expenses of $2.9 million and $5.0 million related to the employee stock ownership plan and charitable donations, respectively, and increased revenues of $3.6 million, $5.4 million, and $3.4 million related to a residential pricing program, customer contracting, and customer facilities charges, respectively. These increases were partially offset by net financial gains on gas hedges of $18.6 million in 2005. Other income and (expense), net increased $21.5 million in 2005 from 2004 primarily due to $16.8 million of additional gas hedge gains. Other income and (expense), net decreased in 2004 primarily due to a $15.5 million disallowance of Plant McIntosh construction costs in December 2004, partially offset by a $7.5 million decrease in donations and $3.4 million in increased income from a customer pricing program. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" and "– Fuel Hedging Program" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, income tax laws are based on historical costs. 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, preferred stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for electricity relating to PPAs, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and revenues are reviewed and adjusted periodically with certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" and "FERC Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area. Assuming normal weather, retail sales growth is expected to be approximately 2.1 percent on average from 2007 to 2011.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company and Alabama Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities, including the Company's Plants Bowen and Scherer. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against the Company has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. These regulatory revisions have been adopted by the State of Georgia. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair, and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the State of Georgia's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. The civil action requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for the Company on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, the Company had invested approximately $1.5 billion in capital projects to comply with these requirements, with annual totals of $351 million, $117 million, and $47 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $955 million, $637 million, and $316 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $1.3 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2, NO_x, and mercury emissions, maintain compliance with existing regulations, and meet new requirements.

Approximately $700 million of the expenditures related to reducing NO_x emissions pursuant to state and federal requirements were in connection with the EPA's one-hour ozone air quality standard and the 1998 regional NO_x reduction rules.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Areas within the Company's service area that were designated as nonattainment under the eight-hour ozone standard include Macon and a 20-county area within metropolitan Atlanta. Macon is in the process of seeking redesignation by the EPA as an attainment area and is preparing a maintenance plan for approval. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, are currently required for Georgia by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within the Company's service area and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA is expected to publish its final rule for implementation of the existing fine particulate matter standard in early 2007. State plans for addressing the nonattainment designations under the existing standard are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. On September 21, 2006, the EPA published a final rule lowering the 24-hour fine particulate matter air quality standard even further and plans to designate nonattainment areas based on the new standard by December 2009. The final outcome of this matter cannot be determined at this time.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by the State of Georgia and therefore, cannot now be determined.

The Company is retrofitting a closed-loop recirculating cooling tower at one facility under the Clean Water Act to cool water prior to discharge and is considering undertaking similar work at an additional facility. The total estimated capital cost for this project is $96 million.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. Southern Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, Southern Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $5.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $18.8 million for the Company, of which $3.9 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC proceeding in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Market-Based Rate Authority" and "Generation Interconnection Agreements" above for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Merger

Effective July 1, 2006, Savannah Electric was merged into the Company. Prior to the merger, Southern Company was the sole common shareholder of both the Company and Savannah Electric. At the time of the merger, each outstanding share of Savannah Electric common stock was cancelled and Southern Company was issued an additional 1,500,000 shares of the Company's common stock, no par value per share. In addition, at the time of the merger, each outstanding share of Savannah Electric's preferred stock was cancelled and converted into the right to receive one share of the Company's 6⅛ percent Series Class A Preferred Stock, Non-Cumulative, Par Value $25 Per Share, resulting in the issuance by the Company of 1,800,000 shares of such Class A Preferred Stock in July 2006. Following completion of the merger, the outstanding capital stock of the Company consists of 9,261,500 shares of common stock, all of which are held by Southern Company, and 1,800,000 shares of Class A Preferred Stock.

With respect to the merger, the Georgia PSC voted on June 15, 2006 to set a Merger Transition Adjustment (MTA) applicable to customers in the former Savannah Electric service territory so that the fuel rate that became effective on July 1, 2006 plus the MTA equals the applicable fuel rate paid by such customers as of June 30, 2006. See "Fuel Cost Recovery" herein for additional information. Amounts collected under the MTA are being credited to customers in the original Georgia Power service territory through a Merger Transition Credit (MTC). The MTA and the MTC will be in effect until December 31, 2007, when the Company's base rates are scheduled to be adjusted.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan. Under the terms of the 2004 Retail Rate Plan, earnings are being evaluated annually against a retail return on common equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent are applied to rate refunds, with the remaining one-third retained by the Company. Retail rates increased by approximately $194 million and customer fees increased by approximately $9 million effective January 1, 2005 to cover the higher costs of purchased power; operations and maintenance expenses; environmental compliance; and continued investment in new generation, transmission and distribution facilities to support growth and ensure reliability. In 2007, the Company will refund 2005 earnings above 12.25 percent retail ROE. No refund is anticipated for 2006.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In March 2006, the Company and Savannah Electric filed a combined request for fuel cost recovery rate changes with the Georgia PSC to be effective July 1, 2006, concurrent with the merger of the companies. On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in the Company's total annual billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required the Company to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, the Company filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate. On November 13, 2006, under agreement with the Georgia PSC staff, the Company filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs.

On February 6, 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million. The order reduced the Company's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires the Company to file for a new fuel cost recovery rate no later than March 1, 2008. The new rates will become effective on March 1, 2007. Estimated under recovered fuel costs through February 2007 are to be recovered through May 2009 for customers in the original Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, the Company had an under recovered fuel balance of approximately $898 million, of which approximately $544 million is included in deferred charges and other assets in the balance sheets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. In accordance with Georgia PSC order, a portion of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets in the balance sheets. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Nuclear

On August 15, 2006, as part of a potential expansion of Plant Vogtle, the Company and Southern Nuclear Operating Company, Inc. (SNC) filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit (ESP) on behalf of the owners of Plant Vogtle. In addition, the Company and SNC notified the NRC of their intent to apply for a combined construction and operating license (COL) in 2008. Ownership agreements have been signed with each of the existing Plant Vogtle co-owners. See Note 4 to the financial statements for additional information on these co-owners. In June 2006, the Georgia PSC approved the Company's request to establish an accounting order that would allow the Company to defer for future recovery the ESP and COL costs, of which the Company's portion is estimated to total approximately $51 million over the next four years. At this point, no final decision has been made regarding actual construction. Any new generation resource must be certified by the Georgia PSC in a separate proceeding.

Other Matters

The Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in Internal Revenue Service (IRS) or Georgia Department of Revenue interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. As a result, compensation cost relating to share-based payment transactions must now be recognized in the Company's financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $218 million with respect to its overfunded defined benefit plan and additional liabilities and deferred credits of $13 million and $255 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007 with no material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Cash flow from operations increased $117 million in 2006, resulting primarily from increased retail operating revenues partially offset by higher fuel inventories and an increase in under recovered deferred fuel costs. In 2005, cash flow from operations increased $58 million resulting primarily from increased retail operating revenues, partially offset by the increase in under recovered deferred fuel costs. In 2004, cash flow from operations decreased $246 million resulting primarily from the increase in under recovered deferred fuel costs.

In 2006, gross property additions were $1.2 billion. These additions were primarily related to transmission and distribution facilities, nuclear fuel, and equipment to comply with environmental standards. The majority of funds needed for gross property additions for the last several years have been provided from operating activities and capital contributions from Southern Company and the issuance of short-term debt. The statements of cash flows provide additional details.

The Company's ratio of common equity to total capitalization – including short-term debt – was 48.6 percent in 2006, 47.9 percent in 2005, and 47.5 percent in 2004. The Company has received investment grade ratings from the major rating agencies with respect to debt, preferred securities, and preferred stock.

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 operating cash flows. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approvals, and other factors.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Georgia PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source for under recovered fuel costs and to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company had credit arrangements with banks totaling $910 million, of which $904 million was unused, at the beginning of 2007. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

At the beginning of 2007, bank credit arrangements were as follows:

		Expires		
Total	Unused	2007	2008	2011
			(in millions)	
$910	$904	$40	$ –	$870

The credit arrangements that expire in 2007 allow for the execution of term loans for an additional two-year period.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefits of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2006, the Company had outstanding $733 million of commercial paper and no extendible commercial notes.

Financing Activities

During 2006, the Company issued $150 million of senior notes and incurred $154 million of obligations related to the issuance of pollution control bonds. The issuances were used to reduce the Company's short-term indebtedness and refund $154 million of higher interest rate obligations related to pollution control bonds, respectively. In addition, $20 million of first mortgage bonds matured.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3 or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2006, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $7.8 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $250 million.

The Company is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for the Company and/or Alabama Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's exposure related to these agreements was approximately $27.4 million.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company has entered into forward starting interest rate swaps that have been designated as hedges. These swaps have a notional amount of $525 million and are related to anticipated debt issuances over the next two years. Subsequent to December 31, 2006, the Company entered into hedges totaling $375 million, also related to anticipated debt issuances over the next two years. The weighted average interest rate on outstanding variable long-term debt that has not been hedged at January 1, 2007 was 4.6 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $5 million at January 1, 2007. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

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 and, to a lesser extent, into similar contracts for gas purchases.

The Company has implemented a fuel hedging program at the instruction of the Georgia PSC. The changes in fair value of energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in millions)	
Contracts beginning of year	**$ 35.3**	$ 7.2
Contracts realized or settled	**40.2**	(46.8)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**(113.5)**	74.9
Contracts end of year	**$ (38.0)**	$ 35.3

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

Source of 2006 Year-End Valuation Prices

	Total	Maturity	
	Fair Value	Year 1	1-3 Years
	(in millions)		
Actively quoted	**$(38.9)**	$(35.9)	$(3.0)
External sources	**0.9**	0.9	-
Models and other methods	**-**	-	-
Contracts end of year	**$(38.0)**	$(35.0)	$(3.0)

Unrealized gains and losses from mark to market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery mechanism. Of the net financial gains, the Company was allowed to retain 25 percent in earnings through June 30, 2006. In 2005, the Company had a total net gain of $74.6 million of which the Company retained $18.6 million. There were no net financial gains in 2006 and 2004. Effective July 1, 2006, the Georgia PSC ordered the suspension of the profit sharing framework related to the fuel hedging program. New profit sharing arrangements as well as other charges to the fuel hedging program are currently under development. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Hedging Program" for additional information. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts (in millions)
Regulatory assets, net	$(38.0)
Net income	-
Total fair value	$(38.0)

Unrealized gains (losses) recognized in income in 2006, 2005, and 2004 were not material. The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.9 billion for 2007, $1.8 billion for 2008, and $1.8 billion for 2009. Environmental expenditures included in these amounts are $955 million, $637 million, and $316 million for 2007, 2008, and 2009, respectively. Actual construction costs may vary from these estimates because of changes in such factors as: business conditions; environmental regulations; nuclear plant regulations; FERC rules and 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.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities and the related interest, preferred stock dividends, leases, derivatives, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[(a)] --					
Principal	$ 304	$ 328	$ 119	$ 4,768	$ 5,519
Interest	285	537	506	5,411	6,739
Preferred stock dividends[(b)]	3	6	6	-	15
Derivative obligations[(c)]	42	4	-	-	46
Operating leases	32	55	44	42	173
Purchase commitments[(d)] --					
Capital[(e)]	1,829	3,437	-	-	5,266
Coal	1,638	2,446	392	44	4,520
Nuclear fuel	94	161	222	169	646
Natural gas[(f)]	647	876	464	1,914	3,901
Purchased power	355	724	479	1,255	2,813
Long-term service agreements	12	26	34	139	211
Trusts --					
Nuclear decommissioning[(g)]	7	14	14	110	145
Postretirement benefits[(h)]	16	43	-	-	59
Total	$5,264	$8,657	$2,280	$13,852	$30,053

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred stock does not mature; therefore, amounts provided are for the next five years only.

(c) For additional information see Notes 1 and 6 to the financial statements.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.6 billion, $1.6 billion, and $1.5 billion, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) Projections of nuclear decommissioning trust contributions are based on the 2004 Retail Rate Plan.

(h) The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, fuel cost recovery, environmental regulations and expenditures, the Company's projections for postretirement benefit trust contributions, financing activities, access to sources of capital, the impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax, 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, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- 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 ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$6,205,620**	$6,064,363	$5,118,751
Sales for resale --			
Non-affiliates	**551,731**	524,800	251,581
Affiliates	**252,556**	275,525	172,375
Other revenues	**235,737**	211,149	185,061
Total operating revenues	**7,245,644**	7,075,837	5,727,768
Operating Expenses:			
Fuel	**2,233,029**	1,937,378	1,288,491
Purchased power --			
Non-affiliates	**332,606**	421,033	316,390
Affiliates	**812,433**	895,243	785,359
Other operations	**1,025,848**	1,009,993	962,390
Maintenance	**534,621**	561,464	522,945
Depreciation and amortization	**498,754**	526,652	296,740
Taxes other than income taxes	**298,824**	276,027	243,051
Total operating expenses	**5,736,115**	5,627,790	4,415,366
Operating Income	**1,509,529**	1,448,047	1,312,402
Other Income and (Expense):			
Allowance for equity funds used during construction	**31,524**	29,145	29,038
Interest income	**2,459**	6,537	6,865
Interest expense, net of amounts capitalized	**(258,437)**	(235,976)	(194,415)
Interest expense to affiliate trusts	**(59,510)**	(59,510)	(44,565)
Distributions on mandatorily redeemable preferred securities	**-**	-	(15,948)
Other income (expense), net	**8,833**	6,971	(14,512)
Total other income and (expense)	**(275,131)**	(252,833)	(233,537)
Earnings Before Income Taxes	**1,234,398**	1,195,214	1,078,865
Income taxes	**442,334**	447,448	393,902
Net Income	**792,064**	747,766	684,963
Dividends on Preferred Stock	**4,839**	3,393	2,170
Net Income After Dividends on Preferred Stock	**$ 787,225**	$ 744,373	$ 682,793

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 792,064**	$ 747,766	$ 684,963
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**588,428**	616,963	385,668
Deferred income taxes and investment tax credits, net	**16,159**	257,501	265,064
Deferred expenses -- affiliates	**1,558**	1,268	(10,563)
Allowance for equity funds used during construction	**(31,524)**	(29,145)	(29,038)
Pension, postretirement, and other employee benefits	**18,604**	(13,335)	(11,002)
Stock option expense	**5,805**	-	-
Tax benefit of stock options	**1,163**	17,263	10,562
Other, net	**1,735**	(8,201)	(27,519)
Changes in certain current assets and liabilities --			
Receivables	**1,193**	(650,593)	(258,737)
Fossil fuel stock	**(194,256)**	(2,898)	(48,668)
Materials and supplies	**31,317**	(55,805)	(224)
Prepaid income taxes	**1,060**	(38,975)	10,624
Other current assets	**774**	3,585	(25,263)
Accounts payable	**(85,189)**	122,117	142,136
Accrued taxes	**82,735**	77,164	(60,859)
Accrued compensation	**(10,328)**	4,162	(6,704)
Other current liabilities	**(21,054)**	34,029	4,012
Net cash provided from operating activities	**1,200,244**	1,082,866	1,024,452
Investing Activities:			
Property additions	**(1,219,498)**	(891,314)	(788,828)
Nuclear decommissioning trust fund purchases	**(464,274)**	(381,235)	(541,048)
Nuclear decommissioning trust fund sales	**457,394**	372,536	532,349
Purchase of property from affiliates	**-**	-	(414,582)
Cost of removal net of salvage	**(33,620)**	(30,764)	(22,642)
Change in construction payables, net of joint owner portion	**35,075**	4,190	1,978
Other	**(16,005)**	(788)	(5,101)
Net cash used for investing activities	**(1,240,928)**	(927,375)	(1,237,874)
Financing Activities:			
Increase in notes payable, net	**406,768**	97,713	91,523
Proceeds --			
Senior notes	**150,000**	625,000	635,000
Preferred stock	**-**	-	45,000
Pollution control bonds	**153,910**	185,000	-
Gross excess tax benefit of stock options	**2,796**	-	-
Mandatorily redeemable preferred securities	**-**	-	200,000
Capital contributions from parent company	**312,544**	149,475	307,323
Other long term debt	**-**	-	10,000
Redemptions --			
Pollution control bonds	**(153,910)**	(185,000)	-
Capital leases	**(136)**	(1,095)	(1,014)
Senior notes	**(150,000)**	(450,000)	(200,000)
First mortgage bonds	**(20,000)**	-	-
Preferred stock	**(14,569)**	-	-
Mandatorily redeemable preferred securities	**-**	-	(240,000)
Other long term debt	**-**	-	(30,000)
Payment of preferred stock dividends	**(2,958)**	(3,246)	(1,479)
Payment of common stock dividends	**(630,000)**	(582,800)	(588,700)
Other	**(8,049)**	(21,760)	(18,514)
Net cash provided from (used for) financing activities	**46,396**	(186,713)	209,139
Net Change in Cash and Cash Equivalents	**5,712**	(31,222)	(4,283)
Cash and Cash Equivalents at Beginning of Year	**11,138**	42,360	46,643
Cash and Cash Equivalents at End of Year	**$ 16,850**	$ 11,138	$ 42,360
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $12,530, $11,949, and $10,392 capitalized, respectively)	**$ 317,536**	$ 263,802	$ 238,270
Income taxes (net of refunds)	**398,735**	196,930	131,696

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

BALANCE SHEETS
At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 16,850**	$ 11,138
Receivables --		
Customer accounts receivable	**474,046**	447,270
Unbilled revenues	**130,585**	148,526
Under recovered regulatory clause revenues	**353,976**	483,673
Other accounts and notes receivable	**93,656**	112,452
Affiliated companies	**21,941**	81,474
Accumulated provision for uncollectible accounts	**(10,030)**	(9,563)
Fossil fuel stock, at average cost	**392,011**	197,754
Vacation pay	**61,907**	59,190
Materials and supplies, at average cost	**304,514**	335,684
Prepaid expenses	**74,788**	73,216
Other	**72,041**	59,373
Total current assets	**1,986,285**	2,000,187
Property, Plant, and Equipment:		
In service	**21,279,792**	20,636,505
Less accumulated provision for depreciation	**8,343,309**	7,972,913
	12,936,483	12,663,592
Nuclear fuel, at amortized cost	**180,129**	134,798
Construction work in progress	**923,948**	584,470
Total property, plant, and equipment	**14,040,560**	13,382,860
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**70,879**	70,664
Nuclear decommissioning trusts, at fair value	**544,013**	486,591
Other	**58,848**	73,271
Total other property and investments	**673,740**	630,526
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**510,531**	512,337
Prepaid pension costs	**688,671**	455,514
Deferred under recovered regulatory clause revenues	**544,152**	343,804
Other regulatory assets	**629,003**	340,938
Other	**235,788**	232,279
Total deferred charges and other assets	**2,608,145**	1,884,872
Total Assets	**$19,308,730**	$17,898,445

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

BALANCE SHEETS

At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 303,906	$ 188,319
Notes payable	733,281	326,513
Accounts payable --		
Affiliated	238,093	305,754
Other	402,222	379,810
Customer deposits	155,763	136,360
Accrued taxes --		
Income taxes	217,603	128,560
Other	275,098	206,687
Accrued interest	74,643	92,109
Accrued vacation pay	49,704	48,388
Accrued compensation	141,356	143,255
Other	125,494	132,547
Total current liabilities	2,717,163	2,088,302
Long-term Debt (See accompanying statements)	4,242,839	4,396,250
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	969,073	969,073
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	2,815,724	2,849,727
Deferred credits related to income taxes	157,297	166,736
Accumulated deferred investment tax credits	282,070	295,024
Employee benefit obligations	698,274	391,854
Asset retirement obligations	626,681	634,932
Other cost of removal obligations	436,137	445,189
Other regulatory liabilities	281,391	99,385
Other	80,839	65,981
Total deferred credits and other liabilities	5,378,413	4,948,828
Total Liabilities	13,307,488	12,402,453
Preferred Stock (See accompanying statements)	44,991	43,909
Common Stockholder's Equity (See accompanying statements)	5,956,251	5,452,083
Total Liabilities and Stockholder's Equity	$19,308,730	$17,898,445
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2006 and 2005
Georgia Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
First mortgage bonds -- 6.9% due May 1, 2006	$ -	$ 20,000		
Long-term notes payable --				
6.20% due February 1, 2006	-	150,000		
4.875% due July 15, 2007	300,000	300,000		
6.55% due May 15, 2008	45,000	45,000		
4.10% due August 15, 2009	125,000	125,000		
Variable rate (5.54% at 1/1/07) due 2009	150,000	150,000		
4.00% due 2011	100,000	100,000		
4.90% to 6.00% due 2012-2045	2,050,000	1,900,000		
Total long-term notes payable	2,770,000	2,770,000		
Other long-term debt --				
Pollution control revenue bonds:				
2.83% to 5.45% due 2012-2036	774,370	812,560		
Variable rate (3.50% to 4.05% at 1/1/07) due 2011-2041	929,475	891,285		
Total other long-term debt	1,703,845	1,703,845		
Capitalized lease obligations	76,227	79,564		
Unamortized debt premium (discount), net	(3,327)	(3,449)		
Total long-term debt (annual interest requirement -- $225.7 million)	4,546,745	4,569,960		
Less amount due within one year	303,906	173,710		
Long-term debt excluding amount due within one year	4,242,839	4,396,250	37.9%	40.5%
Long-term Debt Payable to Affiliated Trusts:				
4.88% to 7.13% due 2042-2044 (annual interest requirement -- $59.5 million)	969,073	969,073	8.6	8.9
Preferred Stock:				
Cumulative preferred stock				
$100 stated value at 4.60%				
Authorized -- 5,000,000 shares				
Outstanding -- 2006: 0 shares				
-- 2005: 145,689 shares	-	14,609		
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized -- 50,000,000 shares				
Outstanding -- 1,800,000 shares	44,991	43,909		
(annual dividend requirement -- $2.8 million)				
Total preferred stock	44,991	58,518		
Less amount due within one year	--	14,609		
Total preferred stock excluding amount due within one year	44,991	43,909	0.4	0.4
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	398,473	398,473		
Paid-in capital	3,039,845	2,717,539		
Retained earnings	2,529,826	2,372,637		
Accumulated other comprehensive income (loss)	(11,893)	(36,566)		
Total common stockholder's equity	5,956,251	5,452,083	53.1	50.2
Total Capitalization	$11,213,154	$10,861,315	100.0%	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$398,473	$2,232,956	$2,116,949	$(25,079)	$4,723,299
Net income after dividends on preferred stock	-	-	682,793	-	682,793
Capital contributions from parent company	-	317,885	-	-	317,885
Other comprehensive income (loss)	-	-	-	(11,961)	(11,961)
Cash dividends on common stock	-	-	(588,700)	-	(588,700)
Other	-	(40)	-	-	(40)
Balance at December 31, 2004	**398,473**	**2,550,801**	**2,211,042**	**(37,040)**	**5,123,276**
Net income after dividends on preferred stock	-	-	744,373	-	744,373
Capital contributions from parent company	-	166,738	-	-	166,738
Other comprehensive income (loss)	-	-	-	474	474
Cash dividends on common stock	-	-	(582,800)	-	(582,800)
Other	-	-	22	-	22
Balance at December 31, 2005	**398,473**	**2,717,539**	**2,372,637**	**(36,566)**	**5,452,083**
Net income after dividends on preferred stock	-	-	**787,225**	-	**787,225**
Capital contributions from parent company	-	**322,306**	-	-	**322,306**
Other comprehensive income (loss)	-	-	-	**5,184**	**5,184**
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	**19,489**	**19,489**
Cash dividends on common stock	-	-	**(630,000)**	-	**(630,000)**
Other	-	-	**(36)**	-	**(36)**
Balance at December 31, 2006	**$398,473**	**$3,039,845**	**$2,529,826**	**$(11,893)**	**$5,956,251**

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

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Georgia Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred stock	**$787,225**	$744,373	$682,793
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $5,143, $(2,216) and $(4,115), respectively	**8,155**	(3,512)	(6,523)
Change in fair value of marketable securities, net of tax of $(494), $317 and $(114), respectively	**(817)**	501	(181)
Changes in fair value of qualifying hedges, net of tax of $(935), $1,522 and $(4,885), respectively	**(1,454)**	2,420	(7,744)
Less: Reclassification adjustment for amounts included in net income, net of tax of $(441), $861 and $1,568, respectively	**(700)**	1,065	2,487
Total other comprehensive income (loss)	**5,184**	474	(11,961)
Comprehensive Income	**$792,409**	$744,847	$670,832

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, the Company, Gulf Power, and Mississippi Power – provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. On January 4, 2006, Southern Company completed the sale of substantially all the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

Effective July 1, 2006, the Company merged with Savannah Electric. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements now reflect the merger as though it had occurred on January 1, 2004. See Note 3 under "Retail Regulatory Matters – Merger" for additional information.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform with the current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its 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.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $386 million in 2006, $348 million in 2005, and $310 million in 2004. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $348 million in 2006, $328 million in 2005, and $311 million in 2004.

The Company has an agreement with Southern Power under which the Company operates and maintains Southern Power owned Plants Dahlberg, Franklin, and Wansley at cost. Billings under these agreements with Southern Power amounted to $5.4 million in 2006, $5.2 million in 2005, and $4.8 million in 2004.

The Company has an agreement with SouthernLINC Wireless under which the Company receives digital wireless communications services and purchases digital equipment. Costs for these services amounted to $7.1 million in 2006, $7.7 million in 2005, and $8.0 million in 2004.

Southern Company's 30 percent ownership interest in Alabama Fuel Products, LLC (AFP), which produces synthetic fuel, was terminated July 1, 2006. The Company has an agreement with an indirect subsidiary of Southern Company that provides services for AFP. Under this agreement, the Company provides certain accounting functions, including processing and paying fuel transportation invoices, and the Company is reimbursed for its expenses. Amounts billed under this agreement totaled approximately $76 million in 2006, $61 million in 2005, and $53 million in 2004. In addition, the Company purchases synthetic fuel from AFP for use at Plant Branch. Fuel purchases totaled $146 million through June 30, 2006, $216 million in 2005, and $163 million in 2004.

The Company has entered into several purchased power agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $407 million, $469 million, and $314 million in 2006, 2005, and 2004, respectively. Additionally, the Company had $28 million and $29 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2006 and 2005, respectively. See Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer. Under this agreement, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $8.0 million in 2006, $4.3 million in 2005, and $6.8 million in 2004. See Note 4 for additional information.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced by Alabama Power, Gulf Power, and Mississippi Power in 2005, assistance provided to aid in storm restoration, including company labor, contract labor, and materials, caused an increase in these activities. The total amount of storm assistance provided to Alabama Power, Gulf Power, and Mississippi Power in 2005 was $4.3 million, $5.0 million, and $55.2 million, respectively. These activities were billed at cost.

Also see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

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" (SFAS No. 71). 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 Company's balance sheets at December 31 relate to the following:

	2006	2005	Note
	(in millions)		
Deferred income tax charges	$ 511	$ 513	(a)
Premium on reacquired debt	171	177	(b)
Vacation pay	62	59	(c)
Corporate building lease	51	52	(d)
Postretirement benefits	15	18	(d)
Generating plant outage costs	56	53	(e)
Underfunded retiree benefit plans	310	-	(f)
Fuel-hedging assets	58	12	(g)
Other regulatory assets	27	30	(d)
Asset retirement obligations	53	71	(a)
Other cost of removal obligations	(436)	(445)	(a)
Deferred income tax credits	(157)	(167)	(a)
Environmental remediation	(16)	(19)	(h)
Purchased power	(19)	(33)	(h)
Overfunded retiree benefit plans	(218)	-	(f)
Fuel-hedging liabilities	(6)	(47)	(g)
Other regulatory liabilities	(4)	(4)	(d)
Total	$ 458	$ 270	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Recorded and recovered or amortized as approved by the Georgia PSC.

(e) See "Property, Plant, and Equipment" herein.

(f) Recovered and amortized over the average remaining service period which may range up to 17 years. See Note 2 under "Retirement Benefits."

(g) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed 42 months. Upon final settlement, costs are recovered through the fuel cost recovery clauses.

(h) Amortized over a three-year period ending in 2007. See Note 3 under "Retail Regulatory Matters – Rate Plans."

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 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, including plant, exists and, write down the assets, if impaired, to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs and the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

Retail fuel cost recovery rates require periodic filings with the Georgia PSC. The Company is required to file its next fuel case by March 1, 2008. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery."

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also 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 $71 million in 2006, $70 million in 2005, and $73 million in 2004.

Nuclear Fuel Disposal Costs

The Company has contracts with the U.S. Department of Energy (DOE) that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract. Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

Also, the Energy Policy Act of 1992 established a Uranium Enrichment Decontamination and Decommissioning Fund, which has been funded in part by a special assessment on utilities with nuclear plants. This assessment was paid over a 15-year period; the final installment occurred in 2006. 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.

State Tax Credits

The State of Georgia provides a tax credit for qualified investment property to manufacturing companies that construct new facilities. The credit ranges from 1 percent to 8 percent of qualified construction expenditures depending upon the county in which the new facility is located. The Company's policy is to recognize these credits when management believes that they are more likely than not to be allowed by the Georgia Department of Revenue. State tax credits of $19.9 million, $9.4 million, and $13.1 million were recorded in 2006, 2005, and 2004, respectively.

Property, Plant, and Equipment

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

The Company's property, plant, and equipment consisted of the following at December 31 (in millions):

	2006	2005
Generation	**$10,064**	$ 9,988
Transmission	**3,331**	3,144
Distribution	**6,652**	6,365
General	**1,205**	1,111
Plant acquisition adjustment	**28**	28
Total plant in service	**$21,280**	$20,636

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for Plants Vogtle and Hatch, respectively. Also, in accordance with the Georgia PSC order, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Income and Other 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. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.6 percent in each of 2006, 2005, and 2004. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2005, the Company's depreciation rates were revised by the Georgia PSC. The revised depreciation rates had no material impact on the Company's financial statements.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the Company's retail rate plan for the three years ending December 31, 2007 (2004 Retail Rate Plan), the Company was ordered to recognize Georgia PSC – certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. The Company recorded a credit to amortization of $14 million in 2006 as well as $33 million in 2005. Under the retail rate plan for the Company ending December 31, 2004 (2001 Retail Rate Plan), the Georgia PSC ordered the Company to amortize $333 million, the cumulative balance of accelerated depreciation and amortization previously expensed, equally over three years as a credit to depreciation and amortization expense beginning January 2002. The Company also was ordered to recognize new certified capacity costs in rates evenly over the same three-year period under the 2001 Retail Rate Plan. As a result, the Company recorded a reduction in depreciation and amortization expense of $77 million in 2004. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal because the timing of their retirements was dependent on future events. The Company has received approval from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plants Hatch and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2006 was $544 million. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, and underground storage tanks. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of approximately $95 million related to asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been recorded because no reasonable estimate can be made regarding the timing of any related retirements. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2006	2005
	(in millions)	
Balance beginning of year	**$635**	$510
Liabilities incurred	**5**	95
Liabilities settled	**(2)**	(3)
Accretion	**41**	33
Cash flow revisions	**(52)**	-
Balance end of year	**$627**	$635

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds to comply with the NRC's regulations. Use of the funds is restricted to nuclear decommissioning activities and the funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The trust funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are classified as available-for-sale. The trust funds are included in the balance sheets at fair value, as obtained from quoted market prices for the same or similar investments. As the external trust funds are actively managed by unrelated parties with limited direction from the Company, the Company does not have the ability to choose to hold securities with unrealized losses until recovery. Through 2005, the Company considered other-than-temporary impairments to be immaterial. However, since the January 1, 2006 effective date of FASB Staff Position FAS 115-1/124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" (FSP No. 115-1), the Company considers all unrealized losses to represent other-than-temporary impairments. The adoption of FSP No. 115-1 had no impact on the results of operations, cash flows, or financial condition of the Company as all losses have been and continue to be recorded through a regulatory liability, whether realized, unrealized, or identified as other-than-temporary. Details of the securities held in these trusts at December 31 are as follows:

2006	Unrealized Gains	Other-than-Temporary Impairments	Fair Value
		(in millions)	
Equity	**$106.9**	**$(5.0)**	**$378.3**
Debt	**3.0**	**(0.7)**	**165.4**
Other	**-**	**-**	**0.3**
Total	**$109.9**	**$(5.7)**	**$544.0**

2005	Unrealized Gains	Unrealized Losses	Fair Value
		(in millions)	
Equity	$76.7	$(6.3)	$325.5
Debt	2.8	(0.8)	135.3
Other	-	-	25.8
Total	$79.5	$(7.1)	$486.6

The contractual maturities of debt securities at December 31, 2006 are as follows: $6.8 million in 2007, $41.0 million in 2008-2011, $42.0 million in 2012-2016, and $75.3 million thereafter.

Sales of the securities held in the trust funds resulted in proceeds of $457.4 million, $372.5 million, and $532.3 million in 2006, 2005, and 2004, respectively, all of which were re-invested. Realized gains and other-than-temporary impairment losses were $17.8 million and $12.1 million, respectively, in 2006. Net realized gains/(losses) were $12.6 million and $14.1 million in 2005 and 2004, respectively. Realized gains and other-than-temporary impairment losses are determined on a specific identification basis. In accordance with regulatory guidance, all realized and unrealized gains and losses are included in the regulatory liability for Asset Retirement Obligations in the balance sheets and are not included in net income or other comprehensive income. Unrealized gains and other-than-temporary impairment losses are considered non-cash transactions for purposes of the statements of cash flows. Unrealized losses were not material in any period presented and did not require the recognition of any impairment to the underlying investments.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only 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. Annual provisions for nuclear decommissioning are based on an annuity method as approved by the Georgia PSC. The amount expensed in 2006 and the accumulated provisions for decommissioning at December 31, 2006 were as follows:

	Plant Hatch	Plant Vogtle
	(in millions)	
Amount expensed in 2006	$ -	$ 6
Accumulated provisions:		
External trust funds, at fair value	$344	$200
Internal reserves	-	1
Total	$344	$201

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2006, which will be filed with the Georgia PSC in 2007 as a part of the retail base rate case. The Company's ownership interests in Plants Hatch and Vogtle were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2061	2051
	(in millions)	
Site study costs:		
Radiated structures	$544	$507
Non-radiated structures	46	67
Total	$590	$574

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

Under the 2004 Retail Rate Plan, effective January 1, 2005, the Georgia PSC decreased the annual decommissioning costs for ratemaking from $9 million to $7 million. This amount is based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2003. The estimates are $421 million and $326 million for Plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 3.1 percent and an estimated trust earnings rate of 5.1 percent. Another significant assumption used was the change in the operating license for Plant Hatch. In January 2002, the NRC granted the Company a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. The Company plans to file an application with the NRC in June 2007 to extend the licenses for Plant Vogtle units 1 and 2 for an additional 20 years. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for the anticipated cost of decommissioning.

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

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. Interest related to the construction of new facilities not included in the Company's retail rates is capitalized in accordance with standard interest capitalization requirements. For the years 2006, 2005, and 2004, the average AFUDC rates were 8.3 percent, 8.0 percent, and 8.0 percent, respectively, and AFUDC capitalized was $44.1 million, $41.1 million, and $39.1 million, respectively. AFUDC and interest capitalized, net of taxes, were 5.0 percent, 4.9 percent, and 5.2 percent of net income after dividends on preferred stock for 2006, 2005, and 2004 respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Retail Regulatory Matters – Rate Plans" for information regarding a regulatory disallowance by the Georgia PSC in December 2004.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. The Company accrues $6.6 million annually that is recoverable through base rates. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Cost Recovery

The Company continues to recover environmental costs through its base rates. Beginning in 2005, such rates include an annual accrual of $5.4 million for environmental remediation. Environmental remediation expenditures will be charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings. Under Georgia PSC ratemaking provisions, $22 million had previously been deferred in a regulatory liability account for use in meeting future environmental remediation costs of the Company and is being amortized over a three-year period that began in January 2005.

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 average costs of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. Prior to January 1, 2006, the Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as of January 1, 2006, for which the requisite service had not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

For the Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings before income taxes and net income of $6 million and $4 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $3 million.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact of fair-value accounting for options granted on net income is as follows:

Net Income	As Reported	Options Impact After Tax	Pro Forma
	(in millions)		
2005	$744	$(3)	$741
2004	$683	$(4)	$679

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	2006	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant-date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2006	**$5,440**	**$5,376**
2005	$5,460	$5,427

The fair values were based on either closing market price or closing price of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in additional minimum pension liability less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts in the balance sheets. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $16 million.

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, the Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to each of its underfunded non-qualified pension plans, the Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

Upon the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life. SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statement of income. Upon the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $218 million with respect to its overfunded defined benefit plan and additional liabilities and deferred credits of $13 million and $255 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans. The incremental effect of applying

SFAS No. 158 on individual line items in the balance sheet at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension costs	$ 471	$ 218	$ 689
Other regulatory assets	319	310	629
Other property and investments	685	(11)	674
Total assets	18,792	517	19,309
Accumulated deferred income taxes	(2,803)	(13)	(2,816)
Other regulatory liabilities	(63)	(218)	(281)
Employee benefit obligations	(431)	(267)	(698)
Total liabilities	(12,810)	(498)	(13,308)
Accumulated other comprehensive income	31	(19)	12
Total stockholders' equity	(5,982)	(19)	(6,001)

Because of pension and postretirement benefit expenses are components of the Company's regulated rates, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, the Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.0 billion in 2006 and $2.0 billion in 2005. Changes during the year in the projected benefit obligations and the fair value of plan assets were as follows:

	2006	2005
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$2,172	$1,989
Service cost	53	47
Interest cost	117	112
Benefits paid	(95)	(90)
Plan amendments	2	13
Actuarial (gain) loss	(113)	101
Balance at end of year	2,136	2,172
Change in plan assets		
Fair value of plan assets at beginning of year	2,493	2,229
Actual return on plan assets	308	346
Employer contributions	6	8
Benefits paid	(95)	(90)
Employee transfers	(2)	-
Fair Value of plan assets at end of year	2,710	2,493
Funded status at end of year	574	321
Unrecognized transition amounts	-	(4)
Unrecognized prior service cost	-	116
Unrecognized net (gain) loss	-	(27)
Fourth quarter contributions	2	2
Prepaid pension asset, net	$ 576	$ 408

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $2.0 billion and $0.1 billion, respectively. All plan assets are related to the qualified plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the

Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	**38%**	40%
International equity	24	**23**	24
Fixed income	15	**16**	17
Real estate	15	**16**	13
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of the following:

	2006	2005
	(in millions)	
Prepaid pension costs	**$ 689**	$ 456
Other regulatory assets	**56**	-
Current liabilities, other	**(6)**	-
Other regulatory liabilities	**(218)**	-
Employee benefit obligations	**(107)**	(109)
Other property and investments	**-**	17
Accumulated other comprehensive income	**-**	45

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year:

	Prior Service Cost	Net (Gain)/ Loss
Balance at December 31, 2006:	(in millions)	
Regulatory asset	**$ 11**	$ 45
Regulatory liabilities	**92**	(310)
Total	**$103**	$(265)
Estimated amortization in net periodic pension cost in 2007:		
Regulatory assets	**$ 2**	$ 3
Regulatory liabilities	**11**	-
Total	**$ 13**	$ 3

Components of net periodic pension cost (income) and other amounts recognized in other comprehensive income were as follows:

	2006	2005	2004
		(in millions)	
Service cost	**$ 53**	$ 47	$ 44
Interest cost	**117**	112	106
Expected return on plan assets	**(184)**	(186)	(184)
Recognized net (gain)/loss	**6**	4	(4)
Net amortization	**8**	9	8
Net pension (income)	**$ -**	$ (14)	$ (30)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	(in millions)
2007	$101
2008	105
2009	110
2010	115
2011	121
2012 to 2016	713

Other Postretirement Benefits

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

	2006	2005
	(in millions)	
Change in benefit obligation		
Balance at beginning of year	$ 812	$ 765
Service cost	11	11
Interest cost	43	43
Benefits paid	(34)	(33)
Actuarial gain (loss)	(27)	26
Retiree drug subsidy	2	-
Balance at end of year	807	812
Change in plan assets		
Fair value of plan assets at beginning of year	362	312
Actual return on plan assets	35	40
Employer contributions	48	43
Benefits paid	(57)	(33)
Fair value of plan assets at end of year	388	362
Funded status at end of year	(419)	(450)
Unrecognized transition amount	-	73
Unrecognized prior service cost	-	26
Unrecognized net (gain) loss	-	215
Fourth quarter contributions	20	23
Accrued liability (recognized in the balance sheet)	$(399)	$(113)

Other postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	42%	44%	46%
International equity	19	20	18
Fixed income	29	27	29
Real estate	6	6	5
Private equity	4	3	2
Total	100%	100%	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2006	2005
	(in millions)	
Other regulatory assets	$ 255	$ -
Employee benefit obligations	(399)	(113)

Presented below are the amounts included in regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost:

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2006			
Regulatory assets	$24	$166	$64
Estimated amortization in net periodic postretirement benefit cost in 2007:			
Regulatory assets	$ 2	$ 8	$ 9

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

	2006	2005	2004
		(in millions)	
Service cost	$ 11	$ 11	$ 11
Interest cost	44	43	43
Expected return on plan assets	(25)	(23)	(26)
Net amortization	22	19	19
Net postretirement cost	$ 52	$ 50	$ 47

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2), related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare

Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced the Company's expenses for the year ended December 31, 2006, the year ended December 31, 2005, and the six months ended December 31, 2004 by approximately $16 million, $11 million, and $5 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
	(in millions)		
2007	$ 37	$ 3	$ 34
2008	41	3	38
2009	45	4	41
2010	48	4	44
2011	52	5	47
2012 to 2016	296	33	263

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$67	$57
Service and interest costs	5	4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $21 million, $20 million, and $19 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities, including the Company's Plants Bowen and Scherer. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after it was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty, and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization, and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit, and on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against the Company has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this case could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Plant Wansley Environmental Litigation

In December 2002, the Sierra Club, Physicians for Social Responsibility, Georgia Forestwatch, and one individual filed a civil suit in the U.S. District Court for the Northern District of Georgia against the Company for alleged violations of the Clean Air Act at four of the units at Plant Wansley. The civil action requested injunctive and declaratory relief, civil penalties, a supplemental environmental project, and attorneys' fees. In January 2007, following the March 2006 reversal and remand by the U.S. Court of Appeals for the Eleventh Circuit, the district court ruled for the Company on all remaining allegations in this case. The only issue remaining for resolution by the district court is the appropriate remedy for two isolated, short-term, technical violations of the plant's Clean Air Act operating permit. The court has asked the parties to submit a joint proposed remedy or individual proposals in the event the parties cannot agree. Although the ultimate outcome of this matter cannot currently be determined, the resulting liability associated with the two events is not expected to have a material impact on the Company's financial statements.

Environmental Remediation

The Company has been designated as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act. In 1995, the EPA designated the Company and four other unrelated entities as potentially responsible parties at a site in Brunswick, Georgia, that is listed on the federal National Priorities List. As of December 31, 2006, the Company had recorded approximately $6 million in cumulative expenses associated with its agreed-upon share of the removal and remedial investigation and feasibility study costs for the Brunswick site. Additional claims for recovery of natural resource damages at the site are anticipated. The Company has also recognized $36 million in cumulative expenses through December 31, 2006 for the assessment and anticipated cleanup of other sites on the Georgia Hazardous Sites Inventory.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $5.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $18.8 million for the Company, of which $3.9 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, the Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. Management believes that the Company has complied with applicable laws and that the plaintiffs' claims are without merit.

In January 2005, the Superior Court of Decatur County, Georgia granted partial summary judgment in a lawsuit brought by landowners against the Company based on the plaintiffs' declaratory judgment claim that the easements do not permit general telecommunications use. The court also dismissed Southern Telecom from this case. The Company appealed this ruling to the Georgia Court of Appeals. The Georgia Court of Appeals reversed, in part, the trial court's order and remanded the case to the trial court for the determination of further issues. After the Court of Appeals' decision, the plaintiffs filed a motion for reconsideration, which was denied, and a petition for certiorari to the Georgia Supreme Court, which was also denied. On October 10, 2006, the Superior Court of Decatur County, Georgia granted the Company's motion for summary judgment. The period during which the plaintiff could have appealed has expired. This matter is now concluded.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, the Company, Gulf Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

The Company is involved in a property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial increases in the ad valorem tax valuation of the Company's 22.95 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003, 2004, and 2005. The Company is aggressively pursuing administrative appeals in Monroe County and has filed notices of arbitration for all three years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, the Company filed suit, on its behalf, against the Monroe Board in the Superior Court of Monroe County. The Company requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from the Company. On December 22, 2005, the court granted Monroe County's motion for summary judgment. The Company has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If the Company is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2006 of up to $18 million, plus penalties and interest. The ultimate outcome of this matter cannot currently be determined.

Retail Regulatory Matters

Merger

Effective July 1, 2006, Savannah Electric was merged into the Company. Prior to the merger, Southern Company was the sole common shareholder of both the Company and Savannah Electric. At the time of the merger, each outstanding share of Savannah Electric common stock was cancelled and Southern Company was issued an additional 1,500,000 shares of the Company's common stock, no par value per share. In addition, at the time of the merger, each outstanding share of Savannah Electric's preferred stock was cancelled and converted into the right to receive one share of the Company's 6⅛ percent Series Class A Preferred Stock, Non-Cumulative, Par Value $25 Per Share, resulting in the issuance by the Company of 1,800,000 shares of such Class A Preferred Stock in July 2006. The exchange of preferred stock was a non-cash transaction for purposes of the statements of cash flows. Following completion of the merger, the outstanding capital stock of the Company consists of 9,261,500 shares of common stock, all of which are held by Southern Company, and 1,800,000 shares of Class A Preferred Stock.

With respect to the merger, the Georgia PSC voted on June 15, 2006 to set a Merger Transition Adjustment (MTA) applicable to customers in the former Savannah Electric service territory so that the fuel rate that became effective on July 1, 2006 plus the MTA equals the applicable fuel rate paid by such customers as of June 30, 2006. See "Fuel Cost Recovery" below for additional information. Amounts collected under the MTA are being credited to customers in the original Georgia Power service territory through a Merger Transition Credit (MTC). The MTA and the MTC will be in effect until December 31, 2007, when the Company's base rates are scheduled to be adjusted.

Rate Plans

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the Company. Under the terms of the 2004 Retail Rate Plan, the Company's earnings are evaluated against a retail return on equity (ROE) range of 10.25 percent to 12.25 percent. Two-thirds of any earnings above 12.25 percent will be applied to rate refunds, with the remaining one-third retained by the Company. Retail rates and customer fees increased by approximately $203 million effective January 1, 2005 to cover the higher costs of purchased power, operating and maintenance expenses, environmental compliance, and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2007, the Company will refund 2005 earnings above 12.25 percent retail ROE. No refunds are anticipated for 2006.

In connection with the 2004 Retail Rate Plan, the Georgia PSC approved the transfer of the Plant McIntosh construction project from Southern Power at a total fair market value of approximately $385 million. This value reflected an approximate $16 million disallowance and reduced the Company's net income by approximately $9.5 million. The Georgia PSC also certified a total completion cost not to exceed $547 million for the project. In June 2005, Plant McIntosh units 10 and 11 were placed into service at a total cost that did not exceed the certified amount. Under the 2004 Retail Rate Plan, the Plant McIntosh revenue requirements impact is being reflected in the Company's rates evenly over the three years ending December 31, 2007.

In May 2005, the Georgia PSC approved a new three-year rate plan for the former Savannah Electric ending May 31, 2008. Under the terms of the plan, earnings were evaluated against a retail ROE range of 9.75 percent to 11.75 percent. Retail base revenues increased in June 2005 by approximately $9.6 million.

The Company is required to file a general rate case by July 1, 2007, in response to which the Georgia PSC would be expected to determine whether the 2004 Retail Rate Plan should be continued, modified, or discontinued. In connection with this case, the former Savannah Electric's base rate tariffs will be combined with the Company's.

Under the terms of the 2001 Retail Rate Plan, earnings were evaluated against a retail return on common equity range of 10 percent to 12.95 percent. The Company's earnings in all three years were within the common equity range. Under the 2001 Retail Rate Plan, the Company amortized a regulatory liability of $333 million, related to previously recorded accelerated amortization expenses, equally over three years beginning in 2002. Also, the 2001 Retail Rate Plan required the Company to recognize capacity and operating and maintenance costs related to certified purchase power contracts evenly into rates over a three-year period ended December 31, 2004.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In March 2006, the Company and Savannah Electric filed a combined request for fuel cost recovery rate changes with the Georgia PSC to be effective July 1, 2006, concurrent with the merger of the companies. On June 15, 2006, the Georgia PSC ruled on the request and approved an increase in the Company's total annual fuel billings of approximately $400 million. The Georgia PSC order provided for a combined ongoing fuel forecast but reduced the requested increase related to such forecast by $200 million. The order also required the Company to file for a new fuel cost recovery rate on a semi-annual basis, beginning in September 2006. Accordingly, on September 15, 2006, the Company filed a request to recover fuel costs incurred through August 2006 by increasing the fuel cost recovery rate. On November 13, 2006, under agreement with the Georgia PSC staff, the Company filed a supplementary request reflecting a forecast of annual fuel costs, as well as updated information for previously incurred fuel costs.

On February 6, 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million. The Georgia PSC order reduced the Company's requested increase in the forecast of annual fuel costs by $40 million and disallowed $4 million of previously incurred fuel costs. The order also requires the Company to file for a new fuel cost recovery rate no later than March 1, 2008. Estimated under recovered fuel costs through February 2007 are to be recovered through May 2009 for customers in the original Georgia Power territory and through November 2009 for customers in the former Savannah Electric territory. As of December 31, 2006, the Company had an under recovered fuel balance of approximately $898 million, of which approximately $544 million is included in deferred charges and other assets in the balance sheets.

In May 2005, the Georgia PSC approved the Company's request to increase customer fuel rates by approximately 9.5 percent to recover under recovered fuel costs of approximately $508 million existing as of May 31, 2005 over a four-year period that began June 1, 2005.

In November 2005, the Georgia PSC voted to approve Savannah Electric's request to increase customer rates to recover estimated under recovered fuel cost of approximately $71.8 million as of November 30, 2005 over an estimated four-year period beginning December 1, 2005, as well as future projected fuel costs.

Fuel Hedging Program

In 2003, the Georgia PSC approved an order allowing the Company to implement a natural gas and oil procurement and hedging program. This order allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels. The order limits the program in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause. Annual net financial gains from the hedging program, through June 30, 2006, were shared with the retail customers receiving 75 percent and the Company retaining 25 percent of the total net gains. Effective July 1, 2006, the Georgia PSC ordered the suspension of the profit sharing framework related to the fuel hedging program. New profit sharing arrangements as well as other changes to the fuel hedging program are currently under development. In 2005, the Company had a total net gain of $74.6 million, of which the Company retained $18.6 million. The Company had no net gains in 2004 or 2006.

4. JOINT OWNERSHIP AGREEMENTS

The Company and an affiliate, Alabama Power, own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice.

The Company's share of expenses included in purchased power from affiliates in the statements of income is as follows:

	2006	2005	2004
	(in millions)		
Energy	$58	$54	$51
Capacity	38	38	36
Total	$96	$92	$87

The Company owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), the city of Dalton, Georgia, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2006, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	Company Ownership	Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,289	$1,857
Plant Hatch (nuclear)	50.1	925	502
Plant Wansley (coal)	53.5	396	179
Plant Scherer (coal)			
Units 1 and 2	8.4	116	60
Unit 3	75.0	565	291
Rocky Mountain (pumped storage)	25.4	170	95
Intercession City (combustion-turbine)	33.3	12	2

At December 31, 2006, the portion of total construction work in progress related to Plants Wansley, Scherer, and Rocky Mountain was $53.1 million, $8.7 million, and $1.6 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

In 2004, in order to avoid the loss of certain federal income tax credits related to the production of synthetic fuel, Southern Company chose to defer certain deductions otherwise available to the subsidiaries. The cash flow benefit associated with the utilization of the tax credits was allocated to the subsidiary that otherwise would have claimed the available deductions on a separate company basis without the deferral. This allocation concurrently reduced the tax benefit of the credits allocated to those subsidiaries that generated the credits. As the deferred expenses are deducted, the benefit of the tax credits will be repaid to the subsidiaries that generated the tax credits. The Company has recorded $9.2 million payable to these subsidiaries in Accumulated Deferred Income Taxes on the balance sheets at December 31, 2006.

The transfer of the Plant McIntosh construction project from Southern Power to the Company resulted in a deferred gain to Southern Power for federal income tax purposes. The Company will reimburse Southern Power for the remaining balance of the related deferred taxes of $5.0 million reflected in Southern Power's future taxable income. $4.5 million of this payable to Southern Power is included in Other Deferred Credits and $0.5 million is included in Affiliated Accounts Payable in the balance sheets at December 31, 2006.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power will reimburse the Company for the remaining balance of the related deferred taxes of $10.0 million reflected in the Company's future taxable income. $8.7 million of this receivable from Southern Power is included in Other Deferred Debits and $1.3 million is included in Affiliated Accounts Receivable in the balance sheets at December 31, 2006.

At December 31, 2006, tax-related regulatory assets were $511 million and tax-related regulatory liabilities were $157 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits.

Details of the federal and state income tax provisions are as follows:

	2006	2005	2004
		(in millions)	
Total provision for income taxes:			
Federal:			
Current	**$393**	$166	$116
Deferred	**7**	226	233
	400	392	349
State:			
Current	**33**	24	13
Deferred	**9**	32	31
Deferred investment tax credits	**-**	-	-
Total	**$442**	$448	$393

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:

	2006	2005
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$2,303**	$2,281
Property basis differences	**568**	558
Employee benefit obligations	**243**	163
Fuel clause under recovery	**365**	335
Premium on reacquired debt	**69**	72
Underfunded benefit plans	**156**	-
Asset retirement obligations	**242**	246
Other	**75**	87
Total	**4,021**	3,742
Deferred tax assets:		
Federal effect of state deferred taxes	**123**	119
Other property basis differences	**138**	139
Other deferred costs	**131**	126
Employee benefit obligations	**226**	73
Other comprehensive income	**9**	25
Overfunded benefit plans	**84**	-
Unbilled revenue	**27**	15
Asset retirement obligations	**242**	246
Other	**41**	40
Total	**1,021**	783
Total deferred tax liabilities, net	**3,000**	2,959
Portion included in current (liabilities) assets, net	**(185)**	(110)
Accumulated deferred income taxes in the balance sheets	**$2,815**	$2,849

In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $13.0 million in 2006, 2005, and 2004. At December 31, 2006, 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:

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	3.1	2.6
Non-deductible book depreciation	**1.1**	1.2	1.2
Other	**(2.5)**	(1.8)	(2.3)
Effective income tax rate	**35.8%**	37.5%	36.5%

In 2006, the Company filed its 2005 income tax returns, which included certain state income tax credits that resulted in a lower effective income tax rate for the year ended December 31, 2006 when compared to 2005. The Company has also filed similar claims for the years 2001 through 2004. Amounts recorded in the Company's financial statements for the year ended December 31, 2006 related to these claims are not material. The Georgia Department of Revenue is currently reviewing these claims. If approved as filed, such claims could have a significant, and possibly material, effect on the Company's net income. The ultimate outcome of this matter cannot now be determined.

6. FINANCING

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or preference stock were outstanding at December 31, 2006. The outstanding Class A preferred stock is subject to redemption at the option of the Company on or after July 1, 2009.

Mandatorily Redeemable Preferred Securities/ Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $969 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2006, preferred securities of $940 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of the scheduled maturities and redemptions of securities due within one year at December 31 is as follows:

	2006	2005
	(in millions)	
Capital lease	$ 4	$ 3
Senior notes	300	150
Preferred stock	-	15
First mortgage bonds	-	20
Total	$304	$188

Redemptions and/or maturities through 2011 applicable to total long-term debt are as follows: $304 million in 2007; $49 million in 2008; $279 million in 2009; $5 million in 2010; and $115 million in 2011.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2006 was $1.7 billion.

Senior Notes

The Company issued $150 million aggregate principal amount of unsecured senior notes in 2006. The proceeds of the issuance were used to repay a portion of the Company's short term indebtedness. At December 31, 2006 and 2005, the Company had $2.8 billion and $2.8 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2006 and 2005, the Company had a capitalized lease obligation for its corporate headquarters building of $72 million and $74 million, respectively, with an interest rate of 8.1 percent. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities." At December 31, 2006 and 2005, the Company had capitalized lease obligations for its Plant Kraft coal unloading dock and its vehicles of $4.1 million and $5.1 million, respectively. However, for ratemaking purposes, these obligations are treated as operating leases and, as such, lease payments are charged to expense as incurred. The annual expense incurred for these leases in 2006, 2005, and 2004 was $9.6 million, $9.7 million, and $9.6 million, respectively.

Bank Credit Arrangements

At the beginning of 2007, the Company had credit arrangements with banks totaling $910 million, of which $904 million was unused. Of these facilities, $40 million expires during 2007, with the remaining $870 million expiring in 2011. The facilities that expire in 2007 provide the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees are less than 1/8 of 1 percent for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2006, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $904 million in unused credit arrangements provides liquidity support to the Company's variable rate pollution control bonds. The amount of variable rate pollution control bonds outstanding requiring liquidity support as of December 31, 2006 was $112 million. In addition, the Company borrows under a commercial paper program and an extendible commercial note program. The amount of commercial paper outstanding at December 31, 2006 was $733 million. The amount of commercial paper outstanding at December 31, 2005 was $327 million. There were no outstanding extendible commercial notes at December 31, 2006. Commercial paper is included in notes payable on the balance sheets.

During 2006, the peak amount of short-term debt outstanding was $757 million and the average amount outstanding was $549 million. The average annual interest rate on short-term debt in 2006 was 5.1 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. See Note 3 under "Retail Regulatory Matters – Fuel Hedging Program" for information on the Company's fuel hedging program. The Company also enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, and 2004.

At December 31, 2006, the fair value gains / (losses) of derivative energy contracts were reflected in the financial statements as follows:

	Amounts
	(in millions)
Regulatory assets, net	$(38.0)
Net income	-
Total fair value	$(38.0)

The fair value gain or loss for hedges that are recoverable through the regulatory fuel clauses are recorded in regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2009.

The Company enters into derivatives to hedge exposure to interest rate changes. Derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings. Subsequent to December 31, 2006, the Company entered into $375 million notional amounts of interest rate swaps to hedge unfavorable changes in interest rates. The hedges will be terminated at the time the underlying debt is issued. In addition to interest rate swaps, the Company has also entered into certain option agreements that effectively cap its interest rate exposure in return for payment of a premium. In some cases, costless collars have been used that effectively establish a floor and a ceiling to interest rate expense.

At December 31, 2006, the Company had $1.2 billion notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains as follows:

Maturity	Weighted Average Fixed Rate Paid	Notional Amount	Fair Value Gain/(Loss)
		(in millions)	
2007	2.68%	$300	$1.4
2007	3.85%*	400	0.1
2017	5.29%	225	(2.0)
2037	5.75%*	300	1.4
2007	2.50%**	14	0.2

* Interest rate collar (showing only the rate cap percentage)
**Hedged using the Bond Market Association Municipal Swap Index

The fair value gain or loss for cash flow hedges is recorded in other comprehensive income and is reclassified into earnings at the same time the hedged items affect earnings. In 2006, 2005, and 2004, the Company settled gains (losses) totaling $(3.9) million, $0.9 million, and $(12.4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. For the years 2006, 2005, and 2004, approximately $1.1 million, $(1.9) million, and $(3.9) million, respectively, of pre-tax gains/(losses) were reclassified from other comprehensive income to interest expense. For 2007, no material pre-tax losses are expected to be reclassified from other comprehensive income to interest expense. The Company has interest related hedges in place through 2037 and has realized gains/(losses) that are being amortized through 2017.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $1.9 billion, $1.8 billion, and $1.8 billion in 2007, 2008, and 2009, respectively. These amounts include $94 million, $73 million, and $88 million in 2007, 2008, and 2009, respectively, for construction expenditures related to contractual purchase commitments for uranium and nuclear fuel conversion, enrichment, and fabrication services included under "Fuel Commitments" herein. The construction program is subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors, including, but not limited to, changes in business conditions, changes in FERC rules and regulations, revised load growth estimates, changes in environmental regulations, changes in existing nuclear plants to meet new regulatory requirements, increasing costs of labor, equipment, and materials, and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

Long-Term Service Agreements

The Company has entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE are made quarterly based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $198.5 million over the remaining term of the agreement, which is currently projected to be approximately 12 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $12.2 million. The contract contains cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

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. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006.

Total estimated minimum long-term obligations at December 31, 2006 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
	(in millions)		
2007	$ 647	$1,638	$ 94
2008	534	1,463	73
2009	342	983	88
2010	202	330	121
2011	262	62	101
2012 and thereafter	1,914	44	169
Total	$3,901	$4,520	$646

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern

Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5 percent interest in Plant Vogtle owned by MEAG that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Except as noted below, the cost of such capacity and energy is included in purchased power from non-affiliates in the statements of income. Capacity payments totaled $49 million, $54 million, and $55 million in 2006, 2005, and 2004, respectively. The current projected Plant Vogtle capacity payments are:

	Capacity Payments
	(in millions)
2007	$ 49
2008	49
2009	54
2010	54
2011	54
2012 and thereafter	200
Total	$460

Portions of the payments noted above relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off.

The Company has entered into other various long-term commitments for the purchase of electricity. Estimated total long-term obligations under these commitments at December 31, 2006 were as follows:

	Commitments	
	Affiliated	Non-Affiliated
	(in millions)	
2007	$220	$86
2008	220	87
2009	220	94
2010	112	96
2011	65	98
2012 and thereafter	390	665
Total	$1,227	$1,126

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $33 million for 2006, $39 million for 2005, and $39 million for 2004.

At December 31, 2006, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
	(in millions)		
2007	$ 18	$14	$ 32
2008	18	11	29
2009	16	10	26
2010	15	7	22
2011	16	6	22
2012 and thereafter	32	10	42
Total	$115	$58	$173

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $64 million. At the termination of the leases, at the Company's option, the Company may either 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. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. Rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC.

Guarantees

Alabama Power 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. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

As discussed earlier in this note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2006, there were 1,651 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed earlier in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options that were used under SFAS No. 123.

The Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject to Option	Weighted-Average Exercise Price
Outstanding at December 31, 2005	7,223,875	$26.87
Granted	1,431,489	33.81
Exercised	(811,013)	24.02
Cancelled	(13,768)	30.97
Outstanding at December 31, 2006	**7,830,583**	**$28.42**
Exercisable at December 31, 2006	**5,106,339**	**$26.14**

The number of stock options vested, and expected to vest in the future, at December 31, 2006 is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

At December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.4 years and 5.3 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $66 million and $55 million, respectively.

As of December 31, 2006, there was $2.5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $10 million, $24 million, and $16 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $9 million, and $6 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (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 the Company's nuclear power plants. The Act provides funds up to $10.76 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of nuclear reactors. A company could be assessed up to $101 million per incident for each licensed reactor it operates but not more than an aggregate of $15 million per incident to be paid in a calendar year for each reactor. Such maximum assessment for the Company, excluding any applicable state premium taxes, based on its ownership and buyback interests, is $203 million per incident but not more than an aggregate of $30 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 additional costs 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 up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL subject to ownership limitations and has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $49 million.

Following the terrorist attacks of September 2001, both ANI and NEIL confirmed that terrorist acts against commercial nuclear power plants would, subject to the normal policy limits, be covered under their insurance. Both companies, however, revised their policy terms on a prospective basis to include an industry aggregate for all "non-certified" terrorist acts i.e., acts that are not certified acts of terrorism pursuant to the Terrorism Risk Insurance Act of 2002, which was renewed in 2005. The aggregate for all NEIL policies, which applies to non-certified property claims stemming from terrorism within a 12-month duration, is $3.24 billion plus any amounts available through reinsurance or indemnity from an outside source. The non-certified ANI nuclear liability cap is a $300 million shared industry aggregate during the normal ANI policy period.

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 information for 2006 and 2005 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred Stock
		(in millions)	
March 2006	**$1,584**	**$288**	**$132**
June 2006	**1,808**	**386**	**197**
September 2006	**2,275**	**662**	**382**
December 2006	**1,579**	**174**	**76**
March 2005	$1,459	$290	$144
June 2005	1,554	325	164
September 2005	2,369	661	375
December 2005	1,694	172	61

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

SELECTED FINANCIAL AND OPERATING DATA 2002-2006

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	**$ 7,245,644**	$ 7,075,837	$ 5,727,768	$ 5,228,625	$ 5,119,466
Net Income after Dividends on Preferred Stock (in thousands)	**$ 787,225**	$ 744,373	$ 682,793	$ 654,036	$ 638,948
Cash Dividends on Common Stock (in thousands)	**$ 630,000**	$ 582,800	$ 588,700	$ 588,800	$ 565,600
Return on Average Common Equity (percent)	**13.80**	14.08	13.87	14.01	13.92
Total Assets (in thousands)	**$19,308,730**	$17,898,445	$16,598,778	$15,527,223	$14,978,520
Gross Property Additions (in thousands)	**$ 1,276,889**	$ 958,563	$ 1,252,197	$ 783,053	$ 916,449
Capitalization (in thousands):					
Common stock equity	**$ 5,956,251**	$ 5,452,083	$ 5,123,276	$ 4,723,299	$ 4,610,396
Preferred stock	**44,991**	43,909	58,547	14,569	14,569
Mandatorily redeemable preferred securities	**-**	-	-	940,000	980,000
Long-term debt payable to affiliated trusts	**969,073**	969,073	969,073	-	-
Long-term debt	**4,242,839**	4,396,250	3,947,621	3,984,825	3,277,671
Total (excluding amounts due within one year)	**$11,213,154**	$10,861,315	$10,098,517	$ 9,662,693	$ 8,882,636
Capitalization Ratios (percent):					
Common stock equity	**53.1**	50.2	50.7	48.9	51.9
Preferred stock	**0.4**	0.4	0.6	0.2	0.2
Mandatorily redeemable preferred securities	**-**	-	-	9.7	11.0
Long-term debt payable to affiliated trusts	**8.6**	8.9	9.6	-	-
Long-term debt	**37.9**	40.5	39.1	41.2	36.9
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred Stock –					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
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	**1,998,643**	1,960,556	1,926,215	1,890,790	1,854,561
Commercial	**294,654**	289,009	283,507	275,378	267,505
Industrial	**8,008**	8,290	7,765	7,989	8,321
Other	**4,371**	4,143	4,015	3,940	3,822
Total	**2,305,676**	2,261,998	2,221,502	2,178,097	2,134,209
Employees (year-end)	**9,278**	9,273	9,294	9,263	9,385

N/A = Not Applicable.

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	**$ 2,326,190**	$ 2,227,137	$ 1,900,961	$ 1,726,543	$ 1,738,206
Commercial	**2,423,568**	2,357,077	1,933,004	1,767,487	1,734,423
Industrial	**1,382,213**	1,406,295	1,217,536	1,051,034	1,036,722
Other	**73,649**	73,854	67,250	63,715	61,972
Total retail	**6,205,620**	6,064,363	5,118,751	4,608,779	4,571,323
Sales for resale – non-affiliates	**551,731**	524,800	251,581	265,029	277,031
Sales for resale – affiliates	**252,556**	275,525	172,375	181,355	102,398
Total revenues from sales of electricity	**7,009,907**	6,864,688	5,542,707	5,055,163	4,950,752
Other revenues	**235,737**	211,149	185,061	173,462	168,714
Total	**$ 7,245,644**	$ 7,075,837	$ 5,727,768	$ 5,228,625	$ 5,119,466
Kilowatt-Hour Sales (in thousands):					
Residential	**26,206,170**	25,508,472	24,829,833	23,532,467	23,900,526
Commercial	**32,112,430**	31,334,182	29,553,893	28,401,764	28,409,596
Industrial	**25,577,006**	25,832,265	27,197,843	26,564,261	26,531,207
Other	**660,285**	737,343	744,935	732,900	731,115
Total retail	**84,555,891**	83,412,262	82,326,504	79,231,392	79,572,444
Sales for resale – non-affiliates	**12,314,322**	11,318,403	6,101,243	8,998,272	8,220,170
Sales for resale – affiliates	**5,494,436**	5,033,165	4,925,744	6,029,398	4,088,440
Total	**102,364,649**	99,763,830	93,353,491	94,259,062	91,881,054
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**8.88**	8.73	7.66	7.34	7.27
Commercial	**7.55**	7.52	6.54	6.22	6.11
Industrial	**5.40**	5.44	4.48	3.96	3.91
Total retail	**7.34**	7.27	6.22	5.82	5.74
Sales for resale	**4.52**	4.89	3.84	2.97	3.08
Total sales	**6.85**	6.88	5.94	5.36	5.39
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,216**	13,119	13,002	12,555	12,990
Residential Average Annual Revenue Per Customer	**$1,173**	$1,145	$995	$921	$945
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,995**	15,995	14,743	14,768	14,847
Maximum Peak-Hour Demand (megawatts):					
Winter	**13,528**	14,360	13,087	13,929	12,539
Summer	**17,159**	16,925	16,129	15,575	15,896
Annual Load Factor (percent)	**61.8**	59.4	61.0	61.6	61.6
Plant Availability (percent):					
Fossil-steam	**91.4**	90.0	87.1	85.9	81.1
Nuclear	**90.7**	89.3	94.8	94.1	88.8
Source of Energy Supply (percent):					
Coal	**58.0**	60.0	57.0	57.9	58.8
Nuclear	**14.2**	14.4	16.4	16.0	15.4
Hydro	**0.9**	1.8	1.5	2.0	0.8
Oil and gas	**4.8**	3.0	0.1	0.3	0.5
Purchased power –					
From non-affiliates	**6.2**	5.6	7.0	7.3	6.2
From affiliates	**15.9**	15.2	18.0	16.5	18.3
Total	**100.0**	100.0	100.0	100.0	100.0

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GULF POWER COMPANY

FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-215 to II-240) present fairly, in all material respects, the financial position of Gulf Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 Gulf Power Company changed its method of accounting for the funded status of defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and storm restoration costs. Appropriately balancing environmental expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida Public Service Commission (PSC) issued an order (2005 Order) that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through a two-year surcharge that began in April 2005. In July 2006, the Florida PSC issued an order (2006 Order) approving another stipulation and settlement between the Company and several consumer groups and thereby authorized an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009. See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 415,000 customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected economic conditions. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2006 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2006 Target Performance	2006 Actual Performance
Customer Satisfaction	Top quartile performance in customer surveys	**Top quartile**
Peak Season EFOR	3.00%	**2.57%**
Net Income	$76.1 million	**$76.0 million**

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2006 net income after dividends on preferred and preference stock was $76.0 million, an increase of $0.8 million from the previous year. In 2005, earnings were $75.2 million, an increase of $7.0 million from the previous year. In 2004, earnings were $68.2 million, a decrease of $0.8 million from the previous year. The increase in earnings in 2006 is due primarily to higher operating revenues partially offset by higher operating expenses, higher financing costs, and increases in depreciation expense. The increase in earnings in 2005 was due primarily to higher retail sales and lower non-fuel operating expenses, excluding expenses related to Hurricane Ivan storm damage, which are offset by revenues and do not affect earnings. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein. The decrease in earnings in 2004 was due primarily to higher operating expenses related to replenishing property damage reserves and increased expenses related to employee benefits.

RESULTS OF OPERATIONS

A condensed statement of income is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
		(in thousands)		
Operating revenues	**$1,203,914**	**$120,292**	$123,491	$82,434
Fuel	**534,921**	**119,132**	48,634	50,652
Purchased power	**73,824**	**(24,573)**	32,500	15,740
Other operation and maintenance	**259,519**	**9,749**	20,058	19,012
Depreciation and amortization	**89,170**	**4,168**	2,203	477
Taxes other than income taxes	**79,808**	**3,421**	6,531	3,741
Total operating expenses	**1,037,242**	**111,897**	109,926	89,622
Operating income	**166,672**	**8,395**	13,565	(7,188)
Total other income and (expense)	**(42,090)**	**(4,764)**	(749)	5,219
Income taxes	**45,293**	**312**	5,286	(1,182)
Net Income	**79,289**	**3,319**	7,530	(787)
Dividends on Preferred and Preference Stock	**3,300**	**2,539**	544	-
Net Income after Dividends on Preferred and Preference Stock	**$ 75,989**	**$ 780**	$ 6,986	$ (787)

Revenues

Operating revenues increased in 2006 when compared to 2005 and 2004. The following table summarizes the changes in operating revenues for the past three years:

	Amount		
	2006	2005	2004
	(in thousands)		
Retail -- prior year	**$ 864,859**	$ 736,870	$699,174
Change in --			
Base rates	**-**	-	-
Sales growth	**2,473**	11,568	4,896
Weather	**2,443**	(4,223)	3,313
Fuel cost recovery and other	**82,263**	120,644	29,487
Retail -- current year	**952,038**	864,859	736,870
Sales for resale --			
Non-affiliates	**87,142**	84,346	73,537
Affiliates	**118,097**	91,352	110,264
Total sales for resale	**205,239**	175,698	183,801
Other operating revenues	**46,637**	43,065	39,460
Total operating revenues	**$1,203,914**	$1,083,622	$960,131
Percent change	**11.1%**	12.9%	9.4%

Retail revenues increased $87 million, or 10.1 percent, in 2006, $128.0 million, or 17.4 percent, in 2005, and $37.7 million, or 5.4 percent, in 2004. The significant factors driving these changes are shown in the table above.

Fuel and other cost recovery includes recovery provisions for fuel expenses and the energy component of purchased power costs, energy conservation costs, purchased power capacity costs, and environmental compliance costs. Annually, the Company petitions for recovery of projected costs including any true-up amount from prior periods, and approved rates are implemented each January. Other cost recovery also includes revenues related to the recovery of incurred costs for storm damage activity as approved by the Florida PSC. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues," "Property Damage Reserve," and "Environmental Cost Recovery" and Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" and "– Storm Damage Cost Recovery" for additional information.

Total sales for resale were $205.2 million in 2006, an increase of $29.5 million, or 16.8 percent, compared to 2005, primarily due to increased energy sales to affiliates to serve their territorial energy requirements. Total sales for resale were $175.7 million in 2005, a decrease of $8.1 million, or 4.4 percent, compared to 2004, primarily due to lower energy sales to affiliates resulting from decreases in the Company's available generation as a result of outages at Plants Crist and Smith. Total sales for resale were $183.8 million in 2004, an increase of $43.8 million, or 31.3 percent, compared to 2003, primarily due to energy sales to affiliates at a higher unit cost resulting from higher incremental fuel prices.

Revenue from sales to affiliated companies will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliate sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings, since the energy is generally sold at marginal cost and energy purchases are generally offset by revenues through the Company's fuel cost recovery clause.

Sales for resale to non-affiliates are predominantly unit power sales under long-term contracts to other Florida utilities. Revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment under the contracts. Energy is generally sold at variable cost. The capacity and energy components under these unit power sales contracts were as follows:

	2006	2005	2004
		(in thousands)	
Unit Power --			
Capacity	**$21,477**	$20,852	$18,780
Energy	**34,597**	33,206	29,360
Total	**$56,074**	$54,058	$48,140

Other operating revenues increased $3.6 million, $3.6 million, and $1.0 million in 2006, 2005, and 2004, respectively, primarily due to an increase in franchise fees, which are proportional to changes in revenue.

Energy Sales

Changes in revenues are influenced heavily by the volume of energy sold each year. Kilowatt-hour (KWH) sales for 2006 and the percent changes by year were as follows:

	KWH 2006	Percent Change 2006	2005	2004
	(in millions)			
Residential	**5,426**	**2.0%**	2.0%	2.2%
Commercial	**3,843**	**2.9**	1.1	2.2
Industrial	**2,136**	**(1.1)**	2.3	(1.6)
Other	**24**	**5.1**	0.7	0.4
Total retail	**11,429**	**1.7**	1.7	1.5
Sales for resale				
Non-affiliates	**2,079**	**(9.4)**	1.7	(9.9)
Affiliates	**2,938**	**48.6**	(36.8)	28.1
Total	**16,446**	**6.0**	(5.6)	3.8

Residential energy sales increased 2.0 percent in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth. Residential energy sales increased 2.0 percent in 2005, compared to 2004, primarily due to customer growth offset by unfavorable weather conditions. Residential energy sales increased 2.2 percent in 2004, compared to 2003, due to more favorable weather conditions and customer growth.

Commercial energy sales increased 2.9 percent in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth. Commercial energy sales increased 1.1 percent in 2005, compared to 2004, primarily due to customer growth offset by unfavorable weather conditions. Commercial energy sales increased 2.2 percent in 2004, compared to 2003, primarily due to more favorable weather conditions and customer growth.

Industrial energy sales decreased 1.1 percent in 2006, compared to 2005, due to reduced demand for and production of building materials and a conversion project by a major paper manufacturer. Industrial energy sales increased 2.3 percent in 2005, compared to 2004, primarily due to additional sales to customers with gas-fired cogeneration resulting from high natural gas prices. Industrial energy sales decreased 1.6 percent in 2004, compared to 2003, primarily due to the short-term outage experienced as a result of Hurricane Ivan in September 2004.

Sales for resale to non-affiliates decreased 9.4 percent in 2006, increased 1.7 percent in 2005, and decreased 9.9 percent in 2004, each compared to the prior year primarily as a result of fluctuations in the fuel cost to produce energy sold to non-affiliated utilities under both long-term and short-term contracts. The degree to which oil and natural gas prices, which are the primary fuel sources for these customers, differ from the Company's fuel costs will influence these changes in sales. The fluctuations in sales have a minimal effect on earnings because the energy is generally sold at variable cost.

Sales for resale to affiliates increased 48.6 percent in 2006 compared to 2005, primarily due to increased territorial energy requirements of affiliates. Sales for resale to affiliates decreased 36.8 percent in 2005 compared to 2004, due to decreases in the Company's available generation as a result of outages at Plants Crist and Smith. Sales for resale increased 28.1 percent in 2004 compared to 2003, primarily to serve affiliates' territorial energy requirements.

Expenses

Fuel and Purchased Power

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generation resources. Details of the Company's amount and sources of generation, the average cost of fuel per net KWH generated, and the average costs of purchased power were as follows:

	2006	2005	2004
Total generation (millions of KWH)	**16,349**	15,024	15,841
Total purchased power (millions of KWH)	**876**	1,172	1,326
Sources of generation (percent) –			
Coal	**87%**	86%	84%
Gas	**13**	14	16
Cost of fuel, generation (cents per net KWH) –			
Coal	**2.68**	2.16	1.83
Gas	**7.24**	6.48	4.95
Average cost of fuel, generated (cents per net KWH)	**3.27**	2.77	2.32
Average cost of purchased power (cents per net KWH)	**8.43**	8.39	4.97

Fuel expense was $535 million in 2006, an increase of $119.1 million, or 28.7 percent, above the prior year costs. This increase was the result of an $82.4 million increase in the cost of fuel and a $36.7 million increase related to total KWH generated. Fuel expense was $416 million in 2005, an increase of $48.6 million, or 13.2 percent, above the prior year costs. This increase was the result of a $67.5 million increase in the cost of fuel and an $18.9 million decrease related to total KWH generated. Fuel expense was $367 million in 2004, an increase of $50.7 million, or 16 percent, above the prior year costs. This increase was the result of an $32.7 million increase in the cost of fuel and a $18 million increase related to total KWH generated.

Purchased power expense was $73.8 million in 2006, a decrease of $24.6 million, or 25.0 percent, below the prior year costs. This decrease was the result of a $24.9 million decrease in total KWH purchased and a $0.3 million increase resulting from the higher average cost per net KWH. Purchased power expense was $98.4 million in 2005, an increase of $32.5 million, or 49.3 percent, above the prior year costs. This increase was the result of a $7.6 million decrease in total KWH purchased and a $40.1 million increase resulting from the higher average cost per net KWH. Purchased power expense was $65.9 million in 2004, an increase of $15.7 million, or 31.4 percent, above the prior year costs. This increase was the result of a $6.6 million decrease in total KWH purchased and a $22.3 million increase resulting from the higher average cost per net KWH.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein and Note 3 to the financial statements for additional information.

Other Operations and Maintenance

In 2006, other operations and maintenance expense increased $9.7 million, or 3.9 percent, compared to the prior year primarily due to a $4.2 million increase in the recovery of incurred costs for storm damage activity as approved by the Florida PSC, a $1.9 million increase in employee benefit expenses, and a $1.1 million increase in property insurance costs. In 2005, other operations and maintenance expense increased $20.1 million, or 8.7 percent, compared to the prior year primarily due to the recovery of $20.4 million in Hurricane Ivan restoration costs as approved by the Florida PSC. Since these storm damage expenses are recognized as revenues are recorded, there is no impact on net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information. In 2004, other operations and maintenance expense increased $19.0 million, or 9.0 percent, compared to the prior year primarily due to increases of $7.9 million in the property damage reserve, $2.9 million in the accrued expenses for uninsured litigation and workers compensation claims, $3.4 million for employee benefit expenses, and $2.5 million for production expenses. See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information on the property damage reserve.

Depreciation and Amortization

Depreciation and amortization expense increased $4.2 million, or 4.9 percent, in 2006 compared to the prior year primarily due to the construction of environmental control projects at Plants Crist and Daniel that were placed in service in 2005. Depreciation and amortization expense increased $2.2 million, or 2.7 percent, in 2005 compared to the prior year primarily due to the completion of environmental control projects at Plant Crist Unit 7. Depreciation and amortization expense remained relatively flat in 2004 compared to the prior year due to no significant change in depreciable assets.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $3.4 million, or 4.5 percent, in 2006, $6.5 million, or 9.3 percent, in 2005, and $3.7 million, or 5.7 percent, in 2004 primarily due to increases in franchise and gross receipts taxes, which are directly related to the increase in retail revenues.

Other Income and (Expense)

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) decreased $0.8 million, or 68.9 percent, in 2006 compared to the prior year primarily due to the completion of an environmental control project at Plant Crist Unit 7. AFUDC decreased $0.7 million, or 37.1 percent, in 2005 and increased $1.1 million, or 160.7 percent, in 2004 compared to the prior year primarily due to the construction and completion of an environmental control project at Plant Crist Unit 7. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein and Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest Income

Interest income increased $1.4 million, or 37.4 percent, in 2006 compared to the prior year primarily due to interest received related to the recovery of financing costs associated with the fuel clause and incurred costs for storm damage activity as approved by the Florida PSC. Interest income increased $2.6 million, or 210.9 percent, in 2005 compared to the prior year primarily due to interest received from a tax refund resulting from Hurricane Ivan and interest received related to the recovery of financing costs associated with Hurricane Ivan. See FUTURE EARNINGS POTENTIAL – "Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information. Interest income remained relatively flat in 2004 compared to the prior year.

Interest Expense

Interest expense, net of amounts capitalized increased $3.9 million, or 10.9 percent, in 2006 compared to the prior year as the result of higher interest rates on variable rate pollution control bonds, increased levels of short-term borrowings at higher interest rates, and the issuance of $60 million in senior notes in August 2005. These increases were partially offset by the maturity of a $100 million bank note in October 2005 and the extinguishment of $30 million aggregate principal amount of first mortgage bonds in 2005. Interest expense increased $4.2 million, or 13.5 percent, in 2005 compared to the prior year as the result of higher interest rates on variable rate pollution control bonds and an increase in outstanding short-term indebtedness as a result of hurricane-related costs. Interest expense decreased $2.1 million, or 5.5 percent, in 2004 compared to the prior year primarily as the result of refinancing higher cost securities.

Other Deductions

Other deductions increased $1.5 million, or 52.9 percent, in 2006, decreased $1.4 million, or 32.2 percent, in 2005, and $1.5 million, or 25.7 percent, in 2004 compared to the prior years as a result of changes in charitable contributions.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for electricity relating to purchased power agreements (PPAs), interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing environmental and fuel costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit partially owned by the Company at Plant Scherer. See Note 4 to the financial statements for information on the Company's ownership interest in Plant Scherer Unit 3. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notices of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted the plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. These regulatory revisions have been adopted by the State of Florida. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the State of Florida's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act;

the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2006, the Company had invested approximately $299 million in capital projects to comply with these requirements, with annual totals of $46 million, $45 million, and $67 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $171 million, $378 million, and $300 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $153.4 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls have been announced and are currently being installed at several plants to further reduce SO_2, NO_x, and mercury emissions, maintain compliance with existing regulations, and meet new requirements.

In 2006, the Company completed implementation of the terms of a 2002 agreement with the State of Florida to help ensure attainment of the ozone standard in the Pensacola, Florida area. The conditions of the agreement, which required installing additional controls on certain units and retiring three older units at a plant near Pensacola, totaled approximately $133.8 million, and have been approved under the Company's environmental cost recovery clause.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. Macon, Georgia, where Plant Scherer is located, was designated as nonattainment under the eight-hour ozone standard. No area within the Company's service area was designated as nonattainment under the eight-hour ozone standard. On December 22, 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the first set of implementation rules adopted in 2004 and remanded the rules to the EPA for further refinement. The impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action and/or rulemaking activity. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, are currently required for most areas by June 2007. These state implementation plans could require further reductions in NO_x emissions from power plants.

During 2005, the EPA's fine particulate matter nonattainment designations became effective for areas within Georgia, and the EPA proposed a rule for the implementation of the fine particulate matter standard. The EPA is expected to publish its final rule for implementation of the existing fine particulate matter standard in early 2007. State plans for addressing the nonattainment designations under the existing standard are required by April 2008 and could require further reductions in SO_2 and NO_x emissions from power plants. On September 21, 2006, the EPA published a final rule lowering the 24-hour fine particulate matter air quality standard even further and plans to designate nonattainment areas based on the new standard by December 2009. The final outcome of this matter cannot be determined at this time.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida, Georgia, and Mississippi are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed, and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

One facility within the Southern Company system is retrofitting a closed-loop recirculating cooling tower under the Clean Water Act to cool water prior to discharge and similar projects are being considered at other facilities.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required clean up costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. Southern Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, Southern Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $3 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, the Company, Mississippi Power, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Market-Based Rate Authority" and "Generation Interconnection Agreements" above for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Florida PSC. At December 31, 2006 and 2005, the under recovered balance was $77.5 million and $31.6 million, respectively, primarily due to increased costs for coal in 2006 and increased costs for coal and natural gas in 2005. The Company continuously monitors the under recovered fuel cost balance in light of these higher fuel costs. If the projected fuel revenue over or under recovery exceeds 10 percent of the projected fuel costs for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

In November 2006, the Florida PSC approved an increase of approximately 28 percent in the fuel factor for retail customers, effective with billings beginning January 2007. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, any change in the billing factor would have no significant effect on the Company's revenues or net income, but would impact annual cash flow.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida PSC issued the 2005 Order that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through the two-year surcharge that began in April 2005.

In July 2006, the Florida PSC issued the 2006 Order approving another stipulation and settlement between the Company and several consumer groups that resolved all matters relating to the Company's request for recovery of incurred costs for storm-recovery activities related to the 2005 storms and the replenishment of the Company's property damage reserve. The 2006 Order provides for an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009.

According to the 2006 Order, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by the Company through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve.

The annual accrual to the reserve of $3.5 million and the Company's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. The Company made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of the 2005 Order regarding Hurricane Ivan costs that established the existing surcharge, the Company agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the 2006 Order do not alter or affect that portion of the prior agreement.

According to the 2006 Order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism.

See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Storm Damage Cost Recovery," respectively, for additional information.

Other Matters

In 2004, Georgia Power and the Company entered into PPAs with Florida Power & Light Company (FP&L) and Progress Energy Florida. Under the agreements, Georgia Power and the Company will provide FP&L and Progress Energy Florida with 165 megawatts and 74 megawatts, respectively, of capacity annually from the jointly owned

Plant Scherer Unit 3 for the period from June 2010 through December 2015. The contracts provide for fixed capacity payments and variable energy payments based on actual energy delivered. The Florida PSC approved the contracts in 2005.

Also in 2004, Georgia Power and the Company entered into a PPA with Flint Electric Membership Corporation. Under the agreement, Georgia Power and the Company will provide Flint Electric Membership Corporation with 75 megawatts of capacity annually from the jointly owned Plant Scherer Unit 3 for the period from June 2010 through December 2019. The contract provides for fixed capacity payments and variable energy payments based on actual energy delivered.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in Internal Revenue Service (IRS) or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other

complaints in which the Company may be asserted to be a potentially responsible party.

- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123(R), "Share-Based Payment" using the modified prospective method. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $23.5 million with respect to its overfunded defined benefit plan and additional liabilities of $2.5 million and $12.9 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plan. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007. The adoption of FIN 48 did not have a material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Net cash flow from operations totaled $143.4 million, $152.7 million, and $144.5 million for 2006, 2005, and 2004, respectively. The $9.3 million decrease in net cash flows in 2006 is due primarily to increased payments related to income taxes and fuel. The $8.2 million increase in net cash flows in 2005 was due primarily to the recovery of Hurricane Ivan restoration costs. The $46.8 million decrease in net cash flows in 2004 was primarily due to payments related to storm damage from Hurricane Ivan. Gross property additions were $147.1 million in 2006. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities. See the statements of cash flows for additional information.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.1 percent in 2006, 43.0 percent in 2005, and 43.2 percent in 2004. See Note 6 to the financial statements for additional information.

The Company has received investment grade ratings from the major rating agencies with respect to its debt, preferred securities, and preference stock.

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 operating cash flows, securities issuances, term loans, and short-term indebtedness. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At the beginning of 2007, the Company had approximately $7.5 million of cash and cash equivalents, along with $120 million of unused committed lines of credit with banks to meet its short-term cash needs. These bank credit arrangements will expire during 2007. The Company plans to renew these lines of credit during 2007. In addition, the Company has substantial cash flow from operating activities and access to the capital markets including commercial paper programs to meet liquidity needs. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. There is no cross affiliate credit support. At December 31, 2006, the Company had $80.4 million in commercial paper notes and $40.0 million in bank notes outstanding.

Financing Activities

In December 2006, the Company issued $110 million of senior notes. A portion of the proceeds of this issuance was used to redeem $30.9 million of long-term debt payable to affiliated trusts. The remainder of the funds from the sale of senior notes was used for general corporate purposes, including the Company's continuous construction program.

On January 19, 2007, the Company issued to Southern Company 800,000 shares of the Company's common stock, without par value, and realized proceeds of $80 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- or Baa3, or below. Generally, collateral may be provided for by a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2006, the maximum potential collateral requirements at a BBB- or Baa3 rating were approximately $23.1 million. The maximum potential collateral requirements at a rating below BBB- or Baa3 were approximately $46.3 million.

The Company, along with all members of the Southern Company power pool, is party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for Alabama Power and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price 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 manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including but not limited to market valuation, value at risk, stress testing, and sensitivity analysis.

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 and, to a lesser extent, into similar contracts for natural gas purchases. The Company has implemented a fuel-hedging program with the approval of the Florida PSC.

The weighted average interest rate on $144.6 million variable long-term debt that has not been hedged at January 1, 2007 was 3.73 percent. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $1.4 million at January 1, 2007. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

The changes in fair value of energy-related derivative contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in thousands)	
Contracts beginning of year	**$ 11,526**	$ 317
Contracts realized or settled	**8,363**	(15,023)
New contracts at inception	**-**	-
Changes in valuation techniques	**-**	-
Current period changes(a)	**(27,075)**	26,232
Contracts end of year	**$ (7,186)**	$ 11,526

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

	Source of 2006 Year-End Valuation Prices		
	Total	Maturity	
	Fair Value	2007	2008-2009
	(in thousands)		
Actively quoted	$(7,324)	$(6,641)	$(683)
External sources	138	138	-
Models and other methods	-	-	-
Contracts end of year	$(7,186)	$(6,503)	$(683)

Unrealized gains and losses from mark-to-market adjustments on derivative contracts related to the Company's fuel hedging programs are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's fuel cost recovery clause. Gains and losses on derivative contracts that are not designated as hedges are recognized in the statements of income as incurred. At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$(7,186)
Net income	-
Total fair value	$(7,186)

Unrealized (losses) recognized in income were not material in any year presented.

The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $278 million in 2007, $458 million in 2008, and $395 million in 2009. The construction program also includes $171 million in 2007, $378 million in 2008, and $300 million in 2009 for environmental expenditures. Actual construction costs may vary from these estimates because of changes in such factors as: business conditions; environmental regulations; FERC rules and 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.

The Company does not have any new generating capacity under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, is ongoing.

The Company has entered into two PPAs, one of which is with Southern Power, for a total of approximately 487 megawatts annually from June 2009 through May 2014. The PPAs are the result of a competitive request for proposals process initiated by the Company in January 2006 to address the anticipated need for additional capacity beginning in 2009. These PPAs are both subject to approval by the Florida PSC for purposes of cost recovery through the Company's purchased power capacity clause, and the PPA with Southern Power is also subject to FERC approval.

As discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in thousands)		
Long-term debt[(a)] --					
Principal	$ -	$ -	$ -	$ 703,793	$ 703,793
Interest	34,924	69,848	69,848	563,334	737,954
Other derivative obligations[(b)]	7,193	838	-	-	8,031
Preference stock dividends[(c)]	3,300	6,600	6,600	-	16,500
Operating leases	4,380	5,635	2,661	3,574	16,250
Purchase commitments[(d)] --					
Capital[(e)]	277,958	852,811	-	-	1,130,769
Coal	281,401	310,220	70,764	-	662,385
Natural gas[(f)]	117,726	156,346	63,275	189,106	526,453
Purchased power	-	23,832	53,672	57,915	135,419
Long-term service agreements	5,940	12,821	16,735	39,419	74,915
Postretirement benefits[(g)]	60,000	120,000	-	-	180,000
Total	$792,822	$1,558,951	$283,555	$1,557,141	$4,192,469

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expense for the last three years were $260 million, $250 million, and $230 million, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's storm damage cost recovery and repairs, retail rates, environmental regulations and expenditures, access to sources of capital, the Company's projections for postretirement benefit trust contributions, financing activities, impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax 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, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against the Company and FERC matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- 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 ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 952,038**	$ 864,859	$736,870
Sales for resale --			
Non-affiliates	**87,142**	84,346	73,537
Affiliates	**118,097**	91,352	110,264
Other revenues	**46,637**	43,065	39,460
Total operating revenues	**1,203,914**	1,083,622	960,131
Operating Expenses:			
Fuel	**534,921**	415,789	367,155
Purchased power --			
Non-affiliates	**16,288**	29,995	30,720
Affiliates	**57,536**	68,402	35,177
Other operations	**192,375**	176,620	160,635
Maintenance	**67,144**	73,150	69,077
Depreciation and amortization	**89,170**	85,002	82,799
Taxes other than income taxes	**79,808**	76,387	69,856
Total operating expenses	**1,037,242**	925,345	815,419
Operating Income	**166,672**	158,277	144,712
Other Income and (Expense):			
Interest income	**5,228**	3,804	1,224
Interest expense, net of amounts capitalized	**(39,619)**	(35,727)	(31,482)
Interest expense to affiliate trusts	**(4,514)**	(4,590)	(3,443)
Distributions on mandatorily redeemable preferred securities	**-**	-	(1,113)
Other income (expense), net	**(3,185)**	(813)	(1,763)
Total other income and (expense)	**(42,090)**	(37,326)	(36,577)
Earnings Before Income Taxes	**124,582**	120,951	108,135
Income taxes	**45,293**	44,981	39,695
Net Income	**79,289**	75,970	68,440
Dividends on Preferred and Preference Stock	**3,300**	761	217
Net Income After Dividends on Preferred and Preference Stock	**$ 75,989**	$ 75,209	$ 68,223

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	$ 79,289	$ 75,970	$ 68,440
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	94,466	90,890	88,772
Deferred income taxes	1,170	33,161	46,255
Pension, postretirement, and other employee benefits	3,319	375	(895)
Stock option expense	1,005	-	-
Tax benefit of stock options	211	3,502	3,063
Hedge settlements	(5,399)	-	-
Other, net	6,931	3,958	11,402
Changes in certain current assets and liabilities --			
Receivables	(36,795)	(46,248)	543
Fossil fuel stock	(31,297)	(11,740)	2,355
Materials and supplies	(2,330)	3,785	(831)
Prepaid income taxes	(7,060)	31,898	(32,343)
Property damage cost recovery	24,544	20,045	-
Other current assets	(955)	3,453	2,721
Accounts payable	13,876	(72,532)	(51,876)
Accrued taxes	(455)	6,847	629
Accrued compensation	(3,251)	311	1,946
Other current liabilities	6,165	9,011	4,325
Net cash provided from operating activities	143,434	152,686	144,506
Investing Activities:			
Property additions	(154,377)	(143,171)	(148,765)
Cost of removal net of salvage	(4,564)	(8,504)	(10,259)
Construction payables	3,309	(8,806)	13,682
Other	(8,779)	(440)	8,952
Net cash used for investing activities	(164,411)	(160,921)	(136,390)
Financing Activities:			
Increase in notes payable, net	30,981	39,465	12,334
Proceeds --			
Senior notes	110,000	60,000	110,000
Other long-term debt	-	-	100,000
Preferred and preference stock	-	55,000	-
Gross excess tax benefit of stock options	423	-	-
Capital contributions from parent company	26,140	(94)	29,481
Redemptions --			
Pollution control bonds	(12,075)	-	-
First mortgage bonds	(25,000)	(30,000)	-
Senior notes	-	-	(125,000)
Other long-term debt	-	(100,000)	-
Preferred and preference stock	-	(4,236)	-
Long-term debt to affiliate trust	(30,928)	-	-
Payment of preferred and preference stock dividends	(3,300)	(761)	(217)
Payment of common stock dividends	(70,300)	(68,400)	(70,000)
Other	(1,285)	(3,721)	(2,433)
Net cash provided from (used for) financing activities	24,656	(52,747)	54,165
Net Change in Cash and Cash Equivalents	3,679	(60,982)	62,281
Cash and Cash Equivalents at Beginning of Year	3,847	64,829	2,548
Cash and Cash Equivalents at End of Year	$ 7,526	$ 3,847	$ 64,829
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $160, $515, and $819 capitalized, respectively)	$ 37,297	$ 35,786	$ 28,796
Income taxes (net of refunds)	54,533	(27,912)	24,130

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

BALANCE SHEETS

At December 31, 2006 and 2005
Gulf Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 7,526	$ 3,847
Receivables --		
Customer accounts receivable	56,489	51,567
Unbilled revenues	38,287	39,951
Under recovered regulatory clause revenues	79,235	33,205
Other accounts and notes receivable	9,015	10,533
Affiliated companies	15,302	24,001
Accumulated provision for uncollectible accounts	(1,279)	(1,134)
Fossil fuel stock, at average cost	76,036	44,740
Materials and supplies, at average cost	35,306	32,976
Property damage cost recovery	28,771	28,744
Other regulatory assets	15,977	9,895
Other	14,259	19,636
Total current assets	374,924	297,961
Property, Plant, and Equipment:		
In service	2,574,517	2,502,057
Less accumulated provision for depreciation	901,564	865,989
	1,672,953	1,636,068
Construction work in progress	62,815	28,177
Total property, plant, and equipment	1,735,768	1,664,245
Other Property and Investments	14,846	6,736
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	17,148	17,379
Prepaid pension costs	69,895	46,374
Other regulatory assets	110,077	123,258
Other	17,831	19,844
Total deferred charges and other assets	214,951	206,855
Total Assets	$2,340,489	$2,175,797

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

BALANCE SHEETS
At December 31, 2006 and 2005
Gulf Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ -	$ 37,075
Notes payable	120,446	89,465
Accounts payable --		
Affiliated	44,375	36,717
Other	49,979	44,139
Customer deposits	21,363	18,834
Accrued taxes --		
Income taxes	29,771	12,823
Other	15,033	11,689
Accrued interest	7,645	7,713
Accrued compensation	16,932	20,336
Other regulatory liabilities	9,029	15,671
Other	30,975	21,844
Total current liabilities	345,548	316,306
Long-term Debt (See accompanying statements)	654,860	544,388
Long-term Debt Payable to Affiliated Trusts (See accompanying statements)	41,238	72,166
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	237,862	256,490
Accumulated deferred investment tax credits	14,721	16,569
Employee benefit obligations	73,922	56,235
Other cost of removal obligations	165,410	153,665
Other regulatory liabilities	46,485	26,795
Other	72,533	76,948
Total deferred credits and other liabilities	610,933	586,702
Total Liabilities	1,652,579	1,519,562
Preferred and Preference Stock (See accompanying statements)	53,887	53,891
Common Stockholder's Equity (See accompanying statements)	634,023	602,344
Total Liabilities and Stockholder's Equity	$2,340,489	$2,175,797
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2006 and 2005
Gulf Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long Term Debt:				
First mortgage bonds --				
6.50% due November 1, 2006	$ -	$ 25,000		
Total first mortgage bonds	-	25,000		
Long-term notes payable --				
4.35% to 5.88% due 2013-2044	**505,000**	395,000		
Total long-term notes payable	**505,000**	395,000		
Other long-term debt --				
Pollution control revenue bonds --				
5.25% due April 1, 2006	-	12,075		
4.80% due September 1, 2028	**13,000**	13,000		
Variable rates (3.53% to 4.04% at 1/1/07) due 2022-2037	**144,555**	144,555		
Total other long-term debt	**157,555**	169,630		
Unamortized debt premium (discount), net	**(7,695)**	(8,167)		
Total long-term debt (annual interest requirement -- $32.6 million)	**654,860**	581,463		
Less amount due within one year	-	37,075		
Long-term debt excluding amount due within one year	**654,860**	544,388	**47.3%**	42.8%
Long-term Debt Payable to Affiliated Trusts:				
5.6% to 7.38% due 2041 through 2042 (annual interest requirement -- $2.3 million)	**41,238**	72,166	**3.0**	5.7
Preferred and Preference Stock:				
Authorized - 2006: 20,000,000 shares--preferred stock				
- 2006: 10,000,000 shares--preference stock				
- 2005: 20,000,000 shares--preferred stock				
- 2005: 10,000,000 shares--preference stock				
Outstanding - $100 par or stated value -- 6% preference stock	**53,887**	53,891		
- 2006: 550,000 shares (non-cumulative)				
- 2005: 550,000 shares (non-cumulative)				
Total preferred and preference stock (annual dividend requirement -- $3.3 million)	**53,887**	53,891	**3.9**	4.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 2006: 20,000,000 shares				
- 2005: 10,000,000 shares				
Outstanding - 2006: 992,717 shares				
- 2005: 992,717 shares	**38,060**	38,060		
Paid-in capital	**428,592**	400,815		
Retained earnings	**171,968**	166,279		
Accumulated other comprehensive income (loss)	**(4,597)**	(2,810)		
Total common stockholder's equity	**634,023**	602,344	**45.8**	47.3
Total Capitalization	**$1,384,008**	$1,272,789	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$38,060	$364,864	$161,208	$(2,774)	$561,358
Net income after dividends on preferred stock	-	-	68,223	-	68,223
Capital contributions from parent company	-	32,544	-	-	32,544
Other comprehensive income (loss)	-	-	-	(91)	(91)
Cash dividends on common stock	-	-	(70,000)	-	(70,000)
Other	-	(12)	150	-	138
Balance at December 31, 2004	38,060	397,396	159,581	(2,865)	592,172
Net income after dividends on preferred stock	-	-	75,209	-	75,209
Capital contributions from parent company	-	3,408	-	-	3,408
Other comprehensive income (loss)	-	-	-	55	55
Cash dividends on common stock	-	-	(68,400)	-	(68,400)
Other	-	11	(111)	-	(100)
Balance at December 31, 2005	38,060	400,815	166,279	(2,810)	602,344
Net income after dividends on preferred and preference stock	-	-	75,989	-	75,989
Capital contributions from parent company	-	27,777	-	-	27,777
Other comprehensive income (loss)	-	-	-	(3,112)	(3,112)
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	1,325	1,325
Cash dividends on common stock	-	-	(70,300)	-	(70,300)
Balance at December 31, 2006	$38,060	$428,592	$171,968	$(4,597)	$634,023

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Gulf Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income after dividends on preferred and preference stock	$75,989	$75,209	$68,223
Other comprehensive income (loss):			
Changes in additional minimum pension liability, net of tax of $(13), $(91) and $(184), respectively	(19)	(146)	(292)
Change in fair value of marketable securities, net of tax of $-, $- and $35, respectively	-	-	56
Changes in fair value of qualifying hedges, net of tax of $(2,082), $- and $-, respectively	(3,317)	-	-
Less: Reclassification adjustment for amounts included in net income, net of tax of $140, $126 and $91, respectively	224	201	145
Total other comprehensive income (loss)	(3,112)	55	(91)
Comprehensive Income	$72,877	$75,264	$68,132

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power, Georgia Power, the Company, and Mississippi Power are vertically integrated utilities providing electric service in four Southeastern states. The Company provides retail service to customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and the subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. On January 4, 2006, Southern Company completed the sale of substantially all of the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its 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.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $59 million, $54 million, and $56 million during 2006, 2005, and 2004, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.0 million, $4.3 million, and $6.8 million and Mississippi Power $19.7 million, $19.5 million, and $17.4 million in 2006, 2005, and 2004, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced in 2004 and 2005, assistance provided to aid in storm restoration, including Company labor, contract labor, and materials, has caused an increase in these activities. The total amount of storm restoration provided to Mississippi Power was $0.2 million and $11.1 million in 2006 and 2005, respectively. The Company received storm restoration assistance from other Southern Company subsidiaries totaling $5.8 million and $12.7 million in 2005 and 2004, respectively. These activities were billed at cost.

The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

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" (SFAS No. 71). 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:

	2006	2005	Note
	(in thousands)		
Environmental remediation	**$ 57,230**	$ 58,235	(a)
Loss on reacquired debt	**18,584**	19,433	(b)
Vacation pay	**5,795**	5,662	(c)
Deferred income tax charges	**17,148**	17,379	(d)
Fuel-hedging assets	**8,031**	2,411	(e)
Underfunded retiree benefit plans	**17,968**	-	(h)
Other assets	**3,319**	3,374	(f)
Under recovered regulatory clause revenues	**77,480**	31,634	(f)
Property damage reserve	**45,654**	74,352	(g)
Asset retirement obligations	**(3,313)**	(640)	(d)
Other cost of removal obligations	**(165,410)**	(153,665)	(d)
Deferred income tax credits	**(17,935)**	(20,627)	(d)
Fuel-hedging liabilities	**(845)**	(13,950)	(e)
Over recovered regulatory clause revenues	**(8,139)**	(5,333)	(f)
Other liabilities	**(1,804)**	(1,916)	(f)
Overfunded retiree benefit plans	**(23,478)**	-	(h)
Total	**$ 30,285**	$ 16,349	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered through the environmental cost recovery clause when the expense is incurred.

(b) Recovered over the remaining life of the original issue, which may range up to 40 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Recorded and recovered or amortized as approved by the Florida PSC. Storm cost recovery surcharge ends in June 2009.

(h) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under "Retirement Benefits."

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 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, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. The Company's retail electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company is required to notify the Florida PSC if the projected fuel revenue over or under recovery exceeds 10 percent of the projected fuel costs for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amount from prior periods, and approved rates are implemented each January.

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

Fuel Costs

Fuel costs are expensed as the fuel is used.

Property, Plant, and Equipment

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

The Company's property, plant, and equipment consisted of the following at December 31:

	2006	2005
	(in thousands)	
Generation	**$1,347,881**	$1,326,766
Transmission	**270,658**	262,168
Distribution	**831,494**	788,711
General	**120,666**	120,339
Plant acquisition adjustment	**3,818**	4,073
Total plant in service	**$2,574,517**	$2,502,057

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed.

Income and Other 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 life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.7 percent in 2006 and 3.8 percent in 2005 and 2004. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate costs of retiring long-lived assets. The present value of the ultimate costs of an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The liability recognized to retire long-lived assets primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, and a barge unloading dock. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of $9.1 million, primarily related to asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the United States Army

Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2006	2005
	(in thousands)	
Balance beginning of year	**$15,298**	$ 5,789
Liabilities incurred	-	9,122
Liabilities settled	-	-
Accretion	**785**	387
Cash flow revisions	**(3,365)**	-
Balance end of year	**$12,718**	$15,298

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. For the years 2006, 2005, and 2004, the average annual AFUDC rate was 7.48 percent. AFUDC, net of taxes, as a percentage of net income after dividends on preferred and preference stock was 0.61 percent, 1.97 percent, and 3.46 percent, respectively, for 2006, 2005, and 2004.

Impairment of Long-Lived Assets and Intangibles

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

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The cost of such damages is charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $6.5 million in 2006, $9.5 million in 2005, and $18.5 million in 2004. At December 31, 2006, the unrecovered balance in the property damage reserve totaled approximately $45.7 million, of which approximately $28.8 million and $16.9 million is included in Current Assets and Deferred Charges and Other Assets, respectively, in the balance sheets. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information regarding the surcharge mechanism approved by the Florida PSC to replenish these reserves.

Environmental Remediation Cost Recovery

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company's environmental remediation liability balances as of December 31, 2006 and 2005 totaled $57.2 million and $58.2 million, respectively. These estimated costs relate to new regulations and more stringent site closure criteria by the Florida Department of Environmental Protection (FDEP) for impacts to groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida

PSC for recovery, as expended, through the Company's environmental cost recovery clause; therefore, there was no impact on the Company's net income as a result of these estimates.

Injuries and Damages Reserve

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $2.0 million and $1.7 million at December 31, 2006 and 2005, respectively, and are included in Current Liabilities in the balance sheets. Liabilities in excess of the reserve balance of $1.7 million and $3.0 million at December 31, 2006 and 2005, respectively, are included in Deferred Credits and Other Liabilities in the balance sheets. Corresponding regulatory assets of $1.6 million at both December 31, 2006 and 2005 are included in Current Assets in the balance sheets. At December 31, 2006 and 2005, respectively, $0.1 million and $1.4 million are included in Deferred Charges and Other Assets in the balance sheets.

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 average 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.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. Prior to January 1, 2006, the Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as of January 1, 2006, for which the requisite service has not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

The compensation cost and tax benefit related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

For the Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings before income taxes and net income of $1.0 million and $0.6 million, respectively, for the year ended December 31, 2006. Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $0.4 million.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact on net income of fair-value accounting for options granted is as follows:

Net Income	As Reported	Options Impact After Tax	Pro Forma
		(in thousands)	
2005	$75,209	$(586)	$74,623
2004	68,223	(522)	67,701

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	2006	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant-date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC-approved hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income.

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

Other financial instruments for which the carrying amounts did not equal fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2006	**$696,098**	**$682,641**
2005	653,629	644,677

The fair values were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in additional minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments for the Company, and the related loans from the trusts are reflected as Long-term Debt Payable to Affiliated Trusts in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides a defined benefit pension plan for a selected group of management and highly compensated employees. Benefits under this non-qualified plan are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the Florida PSC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $60,000.

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, the Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to its underfunded non-qualified pension plan, the Company recognized an additional minimum liability representing the difference between the plan's accumulated benefit obligation and its assets.

With the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet previously unrecognized assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $23.5 million with respect to its overfunded defined benefit plan and additional liabilities of $2.5 million and $12.9 million, respectively, related to its underfunded non-qualified pension plan and retiree benefit plans. The incremental effect of applying SFAS No. 158 on individual line items in the balance sheets at December 31, 2006 follows:

	Before	Adjustments	After
		(in millions)	
Prepaid pension cost	$ 47	$ 23	$ 70
Other regulatory assets	92	18	110
Other property and investments	16	(1)	15
Total assets	2,300	40	2,340
Accumulated deferred income taxes	(237)	(1)	(238)
Other regulatory liabilities	(23)	(23)	(46)
Employee benefit obligation	(59)	(15)	(74)
Total liabilities	(1,614)	(39)	(1,653)
Accumulated other comprehensive income	6	(1)	5
Total stockholder's equity	(687)	(1)	(688)

Because the recovery of postretirement benefit expense through rates is considered probable, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71 with respect to the prepaid assets and the liabilities.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, the Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The accumulated benefit obligation for the pension plans was $242 million in 2006 and $226 million in 2005.

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

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$248,026**	$228,414
Service cost	**6,980**	6,318
Interest cost	**13,359**	12,866
Benefits paid	**(11,034)**	(10,081)
Plan amendments	**385**	1,568
Actuarial (gain) loss	**(11,147)**	8,941
Balance at end of year	**246,569**	248,026
Change in plan assets		
Fair value of plan assets at beginning of year	**280,366**	250,238
Actual return on plan assets	**34,440**	38,478
Employer contributions	**682**	732
Benefits paid	**(11,034)**	(10,081)
Employee transfers	**1,071**	999
Fair value of plan assets at end of year	**305,525**	280,366
Funded status at end of year	**58,956**	32,340
Unrecognized prior service cost	**-**	12,780
Unrecognized net (gain) loss	**-**	(3,845)
Fourth quarter contributions	**147**	200
Prepaid pension asset, net	**$ 59,103**	$ 41,475

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $235.6 million and $10.9 million, respectively. All plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	38%	40%
International equity	24	23	24
Fixed income	15	16	17
Real estate	15	16	13
Private equity	10	7	6
Total	100%	100%	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of the following:

	2006	2005
	(in thousands)	
Prepaid pension costs	**$ 69,895**	$46,374
Other regulatory assets	**5,091**	-
Current liabilities, other	**(585)**	-
Other regulatory liabilities	**(23,478)**	-
Employee benefit obligations	**(10,207)**	(7,893)
Other property and investments	**-**	868
Accumulated other comprehensive income	**-**	2,126

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year:

	Prior Service Cost	Net (Gain)/ Loss
	(in thousands)	
Balance at December 31, 2006:		
Regulatory assets	$ 401	$ 4,690
Regulatory liabilities	11,153	(34,631)
Total	$11,554	$(29,941)

Estimated amortization in net periodic pension cost in 2007:

	Prior Service Cost	Net (Gain)/ Loss
	(in thousands)	
Regulatory assets	$ 114	$360
Regulatory liabilities	1,221	-
Total	$1,335	$360

Components of net periodic pension cost (income) were as follows:

	2006	2005	2004
	(in thousands)		
Service cost	**$ 6,980**	$ 6,317	$ 5,915
Interest cost	**13,358**	12,866	12,136
Expected return on plan assets	**(20,727)**	(20,816)	(20,689)
Recognized net (gain)/loss	**463**	350	(317)
Net amortization	**1,313**	502	486
Net periodic pension cost (income)	**$ 1,387**	$ (781)	$ (2,469)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	(in thousands)
2007	$11,080
2008	11,451
2009	11,852
2010	12,369
2011	13,055
2012 to 2016	77,555

Other Postretirement Benefits

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

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 73,280**	$ 69,186
Service cost	**1,424**	1,357
Interest cost	**3,940**	3,892
Benefits paid	**(3,728)**	(3,124)
Actuarial (gain) loss	**(1,124)**	1,969
Retiree drug subsidy	**193**	-
Balance at end of year	**73,985**	73,280
Change in plan assets		
Fair value of plan assets at beginning of year	**16,434**	14,296
Actual return on plan assets	**1,951**	2,114
Employer contributions	**3,583**	3,148
Benefits paid	**(4,328)**	(3,124)
Fair value of plan assets at end of year	**17,640**	16,434
Funded status at end of year	**(56,345)**	(56,846)
Unrecognized transition amount	**-**	2,589
Unrecognized prior service cost	**-**	4,311
Unrecognized net (gain)/loss	**-**	9,026
Fourth quarter contributions	**932**	973
Accrued liability (recognized in the balance sheet)	**$(55,413)**	$(39,947)

Other postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	35%	**37%**	38%
International equity	23	**22**	23
Fixed income	18	**19**	21
Real estate	14	**15**	12
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2006	2005
	(in thousands)	
Regulatory assets	**$ 12,877**	$ -
Current liabilities, other	**(448)**	-
Employee benefit obligations	**(54,965)**	(39,947)

Presented below are the amounts included in regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in thousands)	
Balance at December 31, 2006:			
Regulatory assets	$3,965	$6,678	$2,234
Estimated amortization as net periodic postretirement benefit cost in 2007:			
Regulatory assets	$ 346	$ 97	$ 356

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

	2006	2005	2004
		(in thousands)	
Service cost	**$ 1,424**	$ 1,357	$ 1,275
Interest cost	**3,940**	3,892	4,081
Expected return on plan assets	**(1,264)**	(1,202)	(1,220)
Transition obligation	**356**	356	355
Prior service cost	**346**	346	346
Recognized net (gain)/loss	**155**	33	241
Net postretirement cost	**$ 4,957**	$ 4,782	$ 5,078

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2) related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $0.5 million, $1.1 million, and $1.7 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2007	$ 3,373	$ (285)	$ 3,088
2008	3,723	(333)	3,390
2009	4,075	(384)	3,691
2010	4,358	(447)	3,911
2011	4,711	(504)	4,207
2012 to 2016	26,937	(3,627)	23,310

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	**$4,586**	**$3,911**
Service and interest costs	**293**	**259**

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $3.0 million, $2.9 million, and $2.7 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after it was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric). The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit partially owned by the Company at Plant Scherer. See Note 4 for information on the Company's ownership interest in Plant Scherer Unit 3. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notices of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted the plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

At December 31, 2006, the Company's liability for the estimated costs of environmental remediation projects for known sites was $57.2 million. The schedule for completion of the remediation projects will be subject to Florida Department of Environmental Protection (FDEP) approval. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause. Therefore, the Company has recorded $1.7 million in Current Assets and Current Liabilities and $55.5 million in Deferred Charges and Other Assets and Deferred Credits and Other Liabilities representing the future recoverability of these costs.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of the Company's activities relating to these sites, management does not believe that the Company's additional liability, if any, at these sites would be material to the financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.8 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $3 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, the Company, Mississippi Power, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due to Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Georgia Power, Mississippi Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties, and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment, and seek compensatory and punitive damages and injunctive relief. The Company's management believes that it has complied with applicable laws and that the plaintiffs' claims are without merit.

In November 2003, the Second Circuit Court in Gadsden County, Florida, ruled in favor of the plaintiffs on their motion for partial summary judgment concerning liability in one such lawsuit brought by landowners regarding the installation and use of fiber optic cable over the Company's rights of way located on the landowners' property. Subsequently, the plaintiffs sought to amend their complaint and asked the court to enter a final declaratory judgment and to enter an order enjoining the Company from allowing expanded general telecommunications use of the fiber optic cables that are the subject of this litigation. In January 2005, the trial court granted in part the plaintiffs' motion to amend their complaint and denied the requested declaratory and injunctive relief. In November 2005, the trial court ruled in favor of the plaintiffs and against the Company on their respective motions for partial summary judgment. In that same order, the trial court also denied the Company's motion to dismiss certain claims. The court's ruling allowed for an immediate appeal to the Florida First District Court of Appeal, which the Company filed in December 2005. On October 26, 2006, the Florida First District Court of Appeal issued an order dismissing the Company's December 2005 appeal on the basis that the trial court's order was a non-final order and therefore not subject to review on appeal at this time. The case is once again pending in the trial court for further proceedings. The final outcome of this matter cannot now be determined. In the event of an adverse verdict in this case, the Company could appeal the issues of both liability and damages or other relief granted.

In addition, in late 2001, certain subsidiaries of Southern Company, including the Company, Alabama Power, Georgia Power, Mississippi Power, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Property Tax Dispute

Georgia Power and the Company are involved in a significant property tax dispute with Monroe County, Georgia (Monroe County). The Monroe County Board of Tax Assessors (Monroe Board) has issued assessments reflecting substantial increases in the ad valorem tax valuation of the Company's 6.25 percent ownership interest in Plant Scherer, which is located in Monroe County, for tax years 2003 through 2006. Georgia Power and the Company are aggressively pursuing administrative appeals in Monroe County and have filed notices of arbitration for all four years. The appeals are currently stayed, pending the outcome of the litigation discussed below.

In November 2004, Georgia Power filed suit, on its own behalf, against the Monroe Board in the Superior Court of Monroe County. The suit could impact all co-owners. Georgia Power contends that Monroe County acted without statutory authority in changing the valuation of a centrally assessed utility as established by the Revenue Commissioner of the State of Georgia and requests injunctive relief prohibiting Monroe County and the Monroe Board from unlawfully changing the value of Plant Scherer and ultimately collecting additional ad valorem taxes from Georgia Power. In December 2005, the Court granted Monroe County's motion for summary judgment. Georgia Power has filed an appeal of the Superior Court's decision to the Georgia Supreme Court.

If Georgia Power is not successful in its administrative appeals and if Monroe County is successful in defending the litigation, the Company could be subject to total additional taxes through December 31, 2006 of up to $4.4 million, plus penalties and interest. In accordance with the Company's unit power sales contract for Plant Scherer, such property taxes would be recoverable from the customer. The final outcome of this matter cannot now be determined.

Retail Regulatory Matters

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA. During 2006, 2005, and 2004, the Company recorded environmental cost recovery clause revenues of $40.9 million, $26.3 million, and $14.7 million, respectively. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2006, the over recovered balance was $6.8 million primarily due to operations and maintenance expenses being less than anticipated.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property.

Hurricanes Dennis and Katrina hit the Gulf Coast of Florida in July 2005 and August 2005, respectively, damaging portions of the Company's service area. In September 2004, Hurricane Ivan hit the Gulf Coast of Florida, causing substantial damage within the Company's service area. In 2005, the Florida PSC issued an order (2005 Order) that approved a stipulation and settlement between the Company and several consumer groups and thereby authorized the recovery of the Company's storm damage costs related to Hurricane Ivan through the two-year surcharge that began in April 2005.

In July 2006, the Florida PSC issued an order (2006 Order) approving another stipulation and settlement between the Company and several consumer groups that resolved all matters relating to the Company's request for recovery of incurred costs for storm-recovery activities related to the 2005 storms and the replenishment of the Company's property damage reserve. The 2006 Order provides for an extension of the storm-recovery surcharge currently being collected by the Company for an additional 27 months, expiring in June 2009.

According to the 2006 Order, the funds resulting from the extension of the current surcharge will first be credited to the unrecovered balance of storm-recovery costs associated with Hurricane Ivan until these costs have been fully recovered. The funds will then be credited to the property reserve for recovery of the storm-recovery costs of $52.6 million associated with Hurricanes Dennis and Katrina that were previously charged to the reserve. Should revenues collected by the Company through the extension of the storm-recovery surcharge exceed the storm-recovery costs associated with Hurricanes Dennis and Katrina, the excess revenues will be credited to the reserve.

The annual accrual to the reserve of $3.5 million and the Company's limited discretionary authority to make additional accruals to the reserve will continue as previously approved by the Florida PSC. The Company made discretionary accruals to the reserve of $3 million, $6 million, and $15 million in 2006, 2005, and 2004, respectively. As part of the 2005 Order regarding Hurricane Ivan costs that established the existing surcharge, the Company agreed that it would not seek any additional increase in its base rates and charges to become effective on or before March 1, 2007. The terms of the 2006 Order do not alter or affect that portion of the prior agreement.

According to the 2006 Order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80 percent of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism.

See Note 1 under "Property Damage Reserve" for additional information.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 megawatts (MW). Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

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

At December 31, 2006, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$191,319[(a)]	$253,370
Accumulated depreciation	90,889	138,472
Construction work in progress	2,430	699
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $3.8 million.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined State of Mississippi and State of Georgia income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

At December 31, 2006, the tax-related regulatory assets to be recovered from customers were $17.1 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 2006, the tax-related regulatory liabilities to be credited to customers were $17.9 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

Details of income tax provisions are as follows:

	2006	2005	2004
		(in thousands)	
Federal –			
Current	**$40,472**	$11,330	$(4,255)
Deferred	**(470)**	26,693	39,373
	40,002	38,023	35,118
State –			
Current	**3,651**	490	(2,305)
Deferred	**1,640**	6,468	6,882
	5,291	6,958	4,577
Total	**$45,293**	$44,981	$39,695

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:

	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$245,147**	$245,906
Fuel recovery clause	**31,380**	12,812
Pension benefits and employee benefit obligations	**23,888**	14,817
Property reserve	**17,612**	29,393
Regulatory assets associated with employee benefit obligations	**10,940**	-
Regulatory assets associated with asset retirement obligations	**5,151**	6,195
Other	**6,492**	6,352
Total	**340,610**	315,475
Deferred tax assets:		
Federal effect of state deferred taxes	**$ 13,713**	$ 13,591
Post retirement benefits	**15,082**	13,430
Pension benefits	**13,310**	2,054
Other comprehensive loss	**2,887**	1,765
Regulatory liabilities associated with employee benefit obligations	**9,057**	-
Asset retirement obligations	**5,151**	6,195
Other	**13,777**	13,082
Total	**72,977**	50,117
Net deferred tax liabilities	**267,633**	265,358
Less current portion, net	**(29,771)**	(8,868)
Accumulated deferred income taxes in the balance sheets	**$237,862**	$256,490

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.8 million in 2006, $1.9 million in 2005, and $2.0 million in 2004. At December 31, 2006, 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:

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.8**	3.7	2.8
Non-deductible book depreciation	**0.5**	0.7	0.6
Difference in prior years' deferred and current tax rate	**(0.8)**	(0.8)	(1.1)
Other, net	**(1.1)**	(1.4)	(0.6)
Effective income tax rate	**36.4%**	37.2%	36.7%

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $41.2 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trusts. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trusts' payment obligations with respect to these securities. At December 31, 2006, $41.2 million of these securities were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2006. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding preference stock is subject to redemption at the option of the Company on or after November 15, 2010.

On January 19, 2007, the Company issued to Southern Company 800,000 shares of the Company's common stock, without par value, and realized proceeds of $80 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds totaling $157.6 million.

Assets Subject to Lien

In January 2007, the Company's first mortgage bond indenture was discharged. As a result, there are no longer any first mortgage liens on the Company's property and the Company no longer has to comply with the covenants and restrictions of the first mortgage bond indenture. The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control bonds with an outstanding principal amount of $41 million.

There are no agreements or other arrangements among the affiliated companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At the beginning of 2007, the Company had $120 million of lines of credit with banks subject to renewal each year, all of which remained unused. Of the $120 million, $116 million provides liquidity support for the Company's commercial paper program and $4 million of daily variable rate pollution control bonds. In connection with these credit lines, the Company has agreed to pay commitment fees.

Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65 percent, as defined in the arrangements. At December 31, 2006, the Company was in compliance with these covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to indebtedness of the

Company. The Company is currently in compliance with all such covenants. In the event of a material adverse change, as defined in the Company's credit agreements, the Company would be prohibited from borrowing against unused credit arrangements totaling $10 million.

The Company borrows primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks and through an extendible commercial note program. At December 31, 2006, the Company had $80.4 million in commercial paper and $40 million in bank notes outstanding. At December 31, 2005, the Company had $14.5 million in commercial paper and $75 million in bank notes outstanding. During 2006, the peak amount outstanding for short-term debt was $181.6 million and the average amount outstanding was $113.8 million. The average annual interest rate on commercial paper was 5.36 percent.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs with the approval of the Florida PSC. The Company enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, and 2004.

At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts (in thousands)
Regulatory assets, net	$(7,186)
Net income	-
Total fair value	$(7,186)

The fair value gains or losses for cash flow hedges that are recoverable through the regulatory fuel clauses are recorded as regulatory assets and liabilities and are recognized in earnings at the same time the hedged items affect earnings. The Company has energy-related hedges in place up to and including 2009.

The Company also may enter into derivatives to hedge exposure to interest rate changes. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings.

In 2006, the Company terminated interest rate derivatives, at the same time the related debt was issued, with a notional value of $80 million at a cost of $5.4 million. The hedge cost will be amortized over a 10-year period. The Company had no interest rate derivatives at December 31, 2006. For the years 2006, 2005, and 2004, approximately $0.4 million, $0.3 million, and $0.3 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2007, pre-tax losses of approximately $0.9 million are expected to be reclassified from other comprehensive income to interest expense. The Company has losses that are being amortized through 2016.

7. COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $278 million in 2007, $458 million in 2008, and $395 million in 2009. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; acquisition of additional generating assets; revised load growth estimates; changes in environmental regulations; changes in FERC rules and regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the ongoing construction program.

Included in the amounts above are $171 million in 2007, $378 million in 2008, and $300 million in 2009 for environmental expenditures. The Company does not have any new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for combined cycle generating facility. The LTSA provides that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under this agreement for facilities owned are currently estimated at $74.9 million over the remaining life of the agreement, which is currently estimated to be up to 9 years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made to GE prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in Current Assets and Deferred Charges and Other Assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Purchased Power and Fuel Commitments

The Company has entered into long-term commitments for the purchase of electricity.

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006.

Total estimated minimum long-term obligations at December 31, 2006 were as follows:

Year	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2007	$ -	$117,726	$281,401
2008	-	90,371	240,222
2009	23,832	65,975	69,998
2010	26,811	43,194	70,764
2011	26,861	20,081	-
2012 and thereafter	57,915	189,106	-
Total commitments	$135,419	$526,453	$662,385

*Included above is $76 million in obligations with affiliated companies.

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $4.9 million, $3.0 million, and $2.0 million, for 2006, 2005, and 2004, respectively. Included in these lease expenses are railcar lease costs which are charged to fuel inventory and are allocated to fuel expense as the fuel is used. These expenses are then recovered through the Company's fuel cost recovery clause. The Company's share of the lease costs charged to fuel inventories was $4.6 million in 2006, $3.0 million in 2005, and $1.9 million in 2004. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

At December 31, 2006, estimated minimum rental commitments for noncancelable operating leases were as follows:

Year	Rail Cars	Other	Total
		(in thousands)	
2007	$ 4,043	$337	$ 4,380
2008	3,072	339	3,411
2009	2,039	185	2,224
2010	2,006	59	2,065
2011	596	-	596
2012 and thereafter	3,574	-	3,574
Total minimum payments	$15,330	$920	$16,250

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's share of these leases was charged to fuel handling expense in the amount of $0.3 million in 2006. The Company's annual lease payments for 2007 to 2010 will average approximately $0.2 million.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2006, there were 283 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options, that were used under SFAS No. 123.

The Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject to Option	Weighted-Average Exercise Price
Outstanding at Dec. 31, 2005	1,099,549	$27.07
Granted	242,373	33.81
Exercised	(142,941)	24.20
Cancelled	(460)	32.66
Outstanding at Dec. 31, 2006	1,198,521	$28.77
Exercisable at Dec. 31, 2006	735,425	$26.27

The number of stock options vested, and expected to vest in the future, as of December 31, 2006 is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

As of December 31, 2006, the weighted average remaining contractual term for options outstanding and options exercisable is 6.6 years and 5.5 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $9.7 million and $7.8 million, respectively.

As of December 31, 2006, there was $0.5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $1.6 million, $4.4 million, and $4.6 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $0.6 million, $1.7 million, and $1.8 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2006 and 2005 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in thousands)	
March 2006	**$263,042**	**$31,079**	**$12,402**
June 2006	**292,722**	**47,062**	**22,038**
September 2006	**373,030**	**66,511**	**34,577**
December 2006	**275,120**	**22,020**	**6,972**
March 2005	$224,597	$31,229	$14,646
June 2005	251,297	44,153	21,458
September 2005	344,080	68,571	37,197
December 2005	263,648	14,324	1,908

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

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SELECTED FINANCIAL AND OPERATING DATA 2002-2006
Gulf Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	$1,203,914	$1,083,622	$ 960,131	$ 877,697	$ 820,467
Net Income after Dividends on Preferred and Preference Stock (in thousands)	$ 75,989	$ 75,209	$ 68,223	$ 69,010	$ 67,036
Cash Dividends on Common Stock (in thousands)	$ 70,300	$ 68,400	$ 70,000	$ 70,200	$ 65,500
Return on Average Common Equity (percent)	12.29	12.59	11.83	12.42	12.72
Total Assets (in thousands)	$2,340,489	$2,175,797	$2,111,877	$1,839,053	$1,816,889
Gross Property Additions (in thousands)	$ 147,086	$ 142,583	$ 161,205	$ 99,284	$ 106,624
Capitalization (in thousands):					
Common stock equity	$ 634,023	$ 602,344	$ 592,172	$ 561,358	$ 549,505
Preferred and preference stock	53,887	53,891	4,098	4,236	4,236
Mandatorily redeemable preferred securities	-	-	-	70,000	115,000
Long-term debt payable to affiliated trusts	41,238	72,166	72,166	-	-
Long-term debt	654,860	544,388	550,989	515,827	452,040
Total (excluding amounts due within one year)	$1,384,008	$1,272,789	$1,219,425	$1,151,421	$1,120,781
Capitalization Ratios (percent):					
Common stock equity	45.8	47.3	48.6	48.8	49.0
Preferred and preference stock	3.9	4.2	0.3	0.4	0.4
Mandatorily redeemable preferred securities	-	-	-	6.1	10.3
Long-term debt payable to affiliated trusts	3.0	5.7	5.9	-	-
Long-term debt	47.3	42.8	45.2	44.7	40.3
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	-	A1	A1	A1	A1
Standard and Poor's	-	A+	A+	A+	A+
Fitch	-	A+	A+	A+	A+
Preferred Stock/ Preference Stock -					
Moody's	Baa1	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
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	364,647	354,466	343,151	341,935	333,757
Commercial	53,466	53,398	51,865	51,169	49,411
Industrial	295	298	285	285	281
Other	484	479	473	473	474
Total	418,892	408,641	395,774	393,862	383,923
Employees (year-end)	1,321	1,335	1,336	1,337	1,339

SELECTED FINANCIAL AND OPERATING DATA 2002-2006 (continued)
Gulf Power Company 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	**$ 510,995**	$ 465,346	$ 401,382	$ 381,464	$ 365,693
Commercial	**305,049**	273,114	232,928	218,928	207,960
Industrial	**132,339**	123,044	99,420	95,702	89,385
Other	**3,655**	3,355	3,140	3,080	2,798
Total retail	**952,038**	864,859	736,870	699,174	665,836
Sales for resale - non-affiliates	**87,142**	84,346	73,537	76,767	77,171
Sales for resale - affiliates	**118,097**	91,352	110,264	63,268	40,391
Total revenues from sales of electricity	**1,157,277**	1,040,557	920,671	839,209	783,398
Other revenues	**46,637**	43,065	39,460	38,488	37,069
Total	**$ 1,203,914**	$ 1,083,622	$ 960,131	$ 877,697	$ 820,467
Kilowatt-Hour Sales (in thousands):					
Residential	**5,425,491**	5,319,630	5,215,332	5,101,099	5,143,802
Commercial	**3,843,064**	3,735,776	3,695,471	3,614,255	3,552,931
Industrial	**2,136,439**	2,160,760	2,113,027	2,146,956	2,053,668
Other	**23,886**	22,730	22,579	22,479	21,496
Total retail	**11,428,880**	11,238,896	11,046,409	10,884,789	10,771,897
Sales for resale - non-affiliates	**2,079,165**	2,295,850	2,256,942	2,504,211	2,156,741
Sales for resale - affiliates	**2,937,735**	1,976,368	3,124,788	2,438,874	1,720,240
Total	**16,445,780**	15,511,114	16,428,139	15,827,874	14,648,878
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**9.42**	8.75	7.70	7.48	7.11
Commercial	**7.94**	7.31	6.30	6.06	5.85
Industrial	**6.19**	5.69	4.71	4.46	4.35
Total retail	**8.33**	7.70	6.67	6.42	6.18
Sales for resale	**4.09**	4.11	3.42	2.83	3.03
Total sales	**7.04**	6.71	5.60	5.30	5.35
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,032**	15,181	15,096	15,064	15,510
Residential Average Annual Revenue Per Customer	**$ 1,416**	$ 1,328	$ 1,162	$ 1,126	$ 1,100
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,659**	2,712	2,712	2,786	2,809
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,195**	2,124	2,061	2,494	2,182
Summer	**2,479**	2,433	2,421	2,269	2,454
Annual Load Factor (percent)	**57.9**	57.7	57.1	54.6	55.3
Plant Availability Fossil-Steam (percent)	**91.3**	89.7	92.4	90.7	90.6
Source of Energy Supply (percent):					
Coal	**82.5**	79.7	77.9	78.7	69.8
Gas	**12.4**	13.1	14.4	11.9	15.5
Purchased power -					
From non-affiliates	**1.9**	2.8	4.5	3.2	4.6
From affiliates	**3.2**	4.4	3.2	6.2	10.1
Total	**100.0**	100.0	100.0	100.0	100.0

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MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-266 to II-292) present fairly, in all material respects, the financial position of Mississippi Power Company at December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, in 2006 Mississippi Power Company changed its method of accounting for the funded status of the defined benefit pension and other postretirement plans.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

Mississippi Power Company (Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a stable regulatory environment, to achieve energy sales growth, and to effectively manage and secure timely recovery of rising costs. These costs include those related to growing demand, increasingly stringent environmental standards, fuel prices, and storm restoration following Hurricane Katrina.

Appropriately balancing environmental expenditures with reasonable retail rates will continue to challenge the Company for the foreseeable future. Hurricane Katrina hit the Gulf Coast of Mississippi in August 2005, causing substantial damage to the Company's service territory as the worst natural disaster in the Company's history. All of the Company's 195,000 customers were without service immediately after the storm. Through a coordinated effort with Southern Company, as well as non-affiliates, the Company restored power to all who could receive it within 12 days. However, over 12,000 customers remained unable to receive service as of December 31, 2006. In October 2006, the Company received from the Mississippi Development Authority (MDA) a Community Development Block Grant (CDBG) in the amount of $276.4 million for costs related to Hurricane Katrina, of which $267.6 million was for the retail portion of the Hurricane Katrina restoration costs.

The Company's retail base rates are set under Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. In December 2005, the Company made its annual PEP filing for the projected 2006 test period and requested an annual five percent, or $32 million, increase in retail base revenues. The retail base rate case became effective April 2006.

In December 2006, the Company made its annual PEP filing for the projected 2007 test period in which no rate change was requested. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

Key Performance Indicators

In striving to maximize shareholder value while providing cost effective energy to customers, the Company continues to focus on several key indicators. These indicators are used to measure the Company's performance for customers and employees.

Recognizing the critical role in the Company's success played by the Company employees, employee-related measures are a significant management focus. These measures include diversity and safety. The 2006 safety performance of the Company was the best in the history of the Company with an Occupational Safety and Health Administration Incidence Rate of 0.39. This achievement resulted in the Company being recognized for the best safety performance among all utilities in the Southeastern Electric Exchange. Inclusion initiatives resulted in a performance above target for the year. In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40 percent); service reliability, measured in outage minutes per customer (40 percent); and customer satisfaction, measured in surveys of residential customers (20 percent). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Management uses customer satisfaction surveys to evaluate the Company's results. Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2006 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2006 Target Performance	2006 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Plant Availability-Peak Season EFOR	3.0% or less	2.26%
Net Income	$77.6 million	$82.0 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2006 reflects the continued emphasis that management places on all of these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $82.0 million in 2006 compared to $73.8 million in 2005. The increase in 2006 is primarily the result of a $25.9 million increase in retail base rates which became effective April 1, 2006, a $4.7 million increase in wholesale base revenues, and a $2.9 million decrease in non-fuel related expenses, partially offset by a $13.3 million increase in depreciation and amortization expenses due to the amortization of a regulatory liability related to Plant Daniel capacity and a depreciation rate increase effective January 1, 2006, an $8.6 million decrease in total other income and expense as a result of charitable contributions, and higher interest rates on long-term debt.

Net income after dividends on preferred stock of $73.8 million in 2005 decreased when compared to $76.8 million in 2004 primarily due to a $15.7 million decrease in retail base revenue due to the loss of customers as a result of Hurricane Katrina and a $2.5 million increase in non-fuel related expenses primarily resulting from increased employee benefit expenses, partially offset by a $5.8 million decrease in depreciation and amortization expenses due to the amortization of a regulatory liability related to Plant Daniel capacity, a $3.3 million increase in wholesale base revenues, a $1.2 million increase in other revenues, and a $2.0 million decrease in dividends on preferred stock as compared to 2004 resulting from the loss on redemption of preferred stock recognized in the third quarter 2004.

The net income after dividends on preferred stock of $76.8 million in 2004 increased when compared to $73.5 million in 2003 due to retail sales growth and higher non-territorial energy sales.

RESULTS OF OPERATIONS

A condensed statement of income is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	**2006**	2005	2004
	(in thousands)			
Operating revenues	**$1,009,237**	**$ 39,504**	$ 59,407	$ 40,402
Fuel	**438,622**	**80,050**	33,690	95,189
Purchased power	**73,247**	**(70,245)**	36,729	13,566
Other operations and maintenance	**236,692**	**(2,930)**	2,144	(62,198)
Depreciation and amortization	**46,853**	**13,304**	(5,841)	(16,310)
Taxes other than income taxes	**60,904**	**846**	4,486	1,581
Total operating expenses	**856,318**	**21,025**	71,208	31,828
Operating income	**152,919**	**18,479**	(11,801)	8,574
Total other income and (expense)	**(21,079)**	**(8,554)**	2,417	1,898
Less -- Income taxes	**48,097**	**1,723**	(4,292)	5,351
Net income	**83,743**	**8,202**	(5,092)	5,121
Dividends on preferred stock	**1,733**	**-**	(2,099)	1,819
Net income after dividends on preferred stock	**$ 82,010**	**$ 8,202**	$ (2,993)	$ 3,302

Revenues

Details of the Company's operating revenues in 2006 and the prior two years are as follows:

	Amount		
	2006	2005	2004
	(in thousands)		
Retail – prior year	**$ 618,860**	$584,313	$516,301
Change in –			
Base rates	**25,872**	-	-
Sales growth and weather	**(137)**	(15,734)	3,555
Fuel cost recovery and other	**2,591**	50,281	64,457
Retail – current year	**647,186**	618,860	584,313
Sales for resale –			
Non-affiliates	**268,850**	283,413	265,863
Affiliates	**76,439**	50,460	44,371
Total sales for resale	**345,289**	333,873	310,234
Other electric operating revenues	**16,762**	17,000	15,779
Total electric operating revenues	**$1,009,237**	$969,733	$910,326
Percent change	**4.1%**	6.5%	4.6%

Total retail revenues for 2006 increased 4.6 percent when compared to 2005 primarily as a result of a retail base rate increase effective April 1, 2006. Higher fuel costs also contributed to the increase. Total retail revenues for 2005 increased 5.9 percent when compared to 2004 as a result of higher fuel revenue due to the increase in fuel cost. This increase in retail revenues was partially offset by reductions for the loss of customers in all major classes as a result of Hurricane Katrina. Total retail revenues for 2004 increased 13.2 percent when compared to 2003. While higher fuel costs accounted for 92 percent of this increase, sales growth, particularly in the industrial class, also contributed to the increase.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The fuel cost recovery and other revenues increased in 2006 when compared to 2005 as a result of higher fuel costs and an increase in kilowatt-hours (KWH) generated. In 2005, fuel cost recovery and other revenues increased as compared to 2004 due to higher fuel costs. During 2004, fuel cost recovery and other revenues increased as compared to 2003 due to an increase in fuel expenses resulting from consistently higher fuel prices.

Sales for resale to non-affiliates are influenced by the non-affiliate utilities' own customer demand, plant availability, and fuel costs. Total revenues from sales for resale to non-affiliates decreased $14.6 million, or 5.1 percent, in 2006 as compared to 2005 as a result of a $14.7 million decrease in energy revenues, of which $10.1 million was associated with decreased sales and $4.6 million was associated with lower fuel prices. In 2005, total revenues from sales for resale to non-affiliates increased $17.5 million, or 6.6 percent, compared to 2004. This increase primarily resulted from an increase in price per KWH resulting from higher fuel costs. Total revenues from sales for resale to non-affiliates increased in 2004 by $15.9 million, or 6.4 percent. This increase primarily resulted from a $34.1 million increase in energy revenues, of which approximately $6 million was associated with increased KWH sales and $27.8 million was associated with higher fuel prices. The increase in energy revenues was offset by an $18.3 million decrease in capacity revenues due to the termination of a contract with Dynegy, Inc. in 2003.

Included in sales for resale to non-affiliates are revenues from rural electric cooperative associations and municipalities located in southeastern Mississippi. Compared to the prior year, KWH sales to these utilities increased 8.9 percent due to growth in the service territory and recovery from Hurricane Katrina in 2006, decreased 5.0 percent due to Hurricane Katrina in 2005, and increased 3.3 percent in 2004, with the related revenues increasing 7.1 percent, 16.2 percent, and 12.4 percent, respectively. The customer demand experienced by these utilities is determined by factors very similar to those experienced by the Company. Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. KWH sales to non-territorial customers decreased 33.0 percent compared to 2005 primarily due to less off-system sales resulting from increased territorial load.

Revenue from energy sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These energy sales do not have a significant impact on earnings since the energy is generally sold at marginal cost.

Energy Sales

KWH sales for 2006 and percent change by year were as follows:

	KWH 2006	Percent Change 2006	2005	2004
	(in millions)			
Residential	**2,118**	**(2.8)%**	(5.1)%	1.9%
Commercial	**2,676**	**(1.8)**	(8.2)	1.9
Industrial	**4,143**	**9.1**	(10.3)	3.0
Other	**37**	**(2.5)**	(5.8)	1.0
Total retail	**8,974**	**2.7**	(8.4)	2.4
Sales for resale				
Non-affiliated	**4,624**	**(3.9)**	(20.2)	2.6
Affiliated	**1,680**	**87.4**	(14.9)	48.6
Total	**15,278**	**5.7**	(13.1)	4.5

Total retail KWH sales increased in 2006 when compared to 2005 due to restoration of customers lost after Hurricane Katrina in 2005. Total retail KWH sales decreased in 2005 when compared to 2004 as the result of the loss of customers following Hurricane Katrina. Total retail KWH sales increased in 2004 when compared to 2003 as a result of economic recovery in the area which affected all customer classes, particularly the industrial class.

Expenses

Total operating expenses increased $21.0 million, or 2.5 percent, in 2006 when compared to 2005 as a result of increases in fuel and purchased power and depreciation and amortization expenses. In 2005 and 2004, total operating expenses increased $71.2 million, or 9.3 percent, and $31.8 million, or 4.3 percent, respectively, primarily as the result of increases in fuel and purchased power, administrative and general expenses, and taxes other than income.

Fuel and Purchased Power

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generation.

Details of the Company's generation, fuel, and purchased power are as follows:

	2006	2005	2004
Total generation (millions of KWH)	**14,224**	12,499	14,058
Total purchased power (millions of KWH)	**1,718**	2,637	3,254
Sources of generation (percent) –			
Coal	**71**	70	69
Gas	**29**	30	31
Cost of fuel, generated (cents per net KWH) –			
Coal	**2.52**	2.24	1.72
Gas	**6.04**	5.94	4.59
Average cost of fuel, generated (cents per net KWH)	**3.34**	3.11	2.50
Average cost of purchased power (cents per net KWH)	**4.26**	5.44	3.28

Fuel and purchased power expenses were $511.9 million in 2006, an increase of $9.8 million, or 2.0 percent, above the prior year costs. This increase was primarily due to an increase of $9.7 million in the cost of fuel and purchased power. In 2005, fuel and purchased power expenses were $502.1 million, an increase of $70.4 million, or 16.3 percent, above the prior year costs. This increase was the result of a $127.6 million increase in the cost of fuel and purchased power and a $57.2 million decrease related to total KWH generated and purchased. Fuel and purchased power expenses in 2004 were $431.6 million, an increase of $108.8 million, or 33.7 percent, above the prior year costs. This increase was the result of a $95.4 million increase in the cost of fuel and purchased power and a $13.3 million increase related to total KWH generated and purchased.

Fuel expense increased $80.1 million in 2006 as compared to 2005 as a result of increases in fuel costs and an increase in generation. This increase in fuel expense is due to a $30.0 million increase in the cost of fuel due to higher coal, gas, transportation, and emission allowance prices and a $50.0 million increase related to more KWH generated. Fuel expense increased $33.7 million in 2005 as compared to 2004. Approximately $71 million in additional fuel expenses resulted from higher coal, gas, transportation prices, and emission allowances, which were partially offset by a $36 million decrease resulting from unit outages that reduced generation. Fuel expense for 2004 increased $95.2 million as compared to 2003. Approximately $25 million of the increase was associated with increased generation and approximately $70 million of the increase was due to higher coal and gas prices.

Purchased power expense decreased $70.2 million, or 49 percent, in 2006 when compared to 2005. The decrease was primarily due to more generation being available to meet customer demand and a decrease in the cost of purchased power. Purchased power expense increased $36.7 million, or 34.4 percent, in 2005 when compared to 2004. The increase is primarily the result of the reduction in generation due to the damage caused by Hurricane Katrina. In 2004, purchased power expense increased $13.6 million, or 14.6 percent, when compared to 2003. The increase was primarily due to an increase in purchases from non-affiliates to meet increased customer demand at lower prices than self-generation. Energy purchases vary from year to year depending on demand and the availability and cost of the Company's generating resources. These expenses do not have a significant impact on earnings since the energy purchases are generally offset by energy revenues through the Company's fuel cost recovery clause.

While prices have moderated somewhat in 2006, a significant upward trend in the cost of coal and natural gas has emerged since 2003, and volatility in these markets is expected to continue. Increased coal prices have been influenced by a worldwide increase in demand as a result of rapid economic growth in China, as well as by increases in mining and fuel transportation costs. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by the 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Other Operations and Maintenance

Total other operations and maintenance expense decreased $2.9 million from 2005 to 2006. Other operations expense increased $1.9 million, or 1.1 percent, in 2006 compared to 2005 primarily as a result of a $1.8 million increase in distribution operations expense and a $1.5 million increase in employee benefit expenses, partially offset by a $1.0 million decrease in bad debt expense. In 2005, other operations expense increased $7.9 million, or 4.9 percent, compared to 2004 primarily as a result a $5.2 million increase in employee benefit expenses, a $1.7 million increase in rent expense on the Plant Daniel combined cycle lease, and higher bad debt expense of $1.0 million primarily resulting from Hurricane Katrina. In 2004, other operations expense decreased $69.2 million, or 30 percent, due to approximately $11 million incurred in 2003 to restructure the Plant Daniel combined cycle lease agreement and $60 million in expense recorded in 2003 in connection with the recognition of a regulatory liability following an accounting order from the Mississippi PSC related to Plant Daniel capacity expense. See FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements" and Notes 3 and 7 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" and "Operating Leases – Plant Daniel Combined Cycle Generating Units," respectively, for additional information.

Maintenance expense decreased $4.9 million, or 6.8 percent, in 2006, primarily due to the $3.4 million accrual of certain expenses arising from Hurricane Katrina related to the wholesale portion of the business in 2005 and the $2.8 million partial recovery of these expenses from the CDBG in 2006, partially offset by a $0.5 million increase in 2006 due to the increased operation of combined cycle units as gas costs decreased in 2006 when compared to 2005. Maintenance expense decreased $5.7 million, or 7.5 percent, in 2005 primarily as a result of a $1.1 million decrease in the operation of combined cycle units due to higher gas prices in 2005 when compared to 2004 and a $4.5 million decrease in maintenance expense associated with changes in scheduled maintenance as a result of restoration efforts. These restoration expenses have been deferred in accordance with a Mississippi PSC order. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information. In 2004, maintenance expense increased $7.0 million, or 9.9 percent, over the prior year, primarily resulting from higher operation of combined cycle units and increased distribution line maintenance during 2004 as compared to 2003. See Note 7 to the financial statements under "Long-Term Service Agreements" for further information.

Depreciation and Amortization

Depreciation and amortization expenses increased $13.3 million in 2006 compared to 2005 due to amortization related to a regulatory liability recorded in 2003 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity and the impact of a new depreciation study effective January 1, 2006. Depreciation and amortization expenses decreased $5.8 million in 2005 and $16.3 million in 2004 as compared to the prior years primarily as a result of amortization related to a regulatory liability recorded in 2003 in connection with the Mississippi PSC's accounting order on the Plant Daniel capacity. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased 1.4 percent in 2006 compared to 2005 primarily as a result of a $0.5 million increase in ad valorem taxes and a $0.3 million increase in municipal franchise taxes. The retail portion, or approximately 83 percent, of the increase in ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income. The increase in municipal franchise taxes is directly related to the increase in total retail revenues. In 2005, taxes other than income taxes increased 8.1 percent over the prior year primarily due to a $2.9 million increase in ad valorem taxes and a $1.1 million increase in municipal franchise taxes. Taxes other than income taxes increased 2.9 percent in 2004 as compared to 2003 primarily due to additional municipal franchise taxes.

Total Other Income and (Expense)

The $8.6 million decrease in total other income and expense in 2006 compared to 2005 is primarily due to charitable contributions and higher interest rates on long-term debt. The increases in total other income and expense in 2005 compared to 2004 are due to a reversal, as a result of changes in the legal and regulatory environment, of a $2.5 million liability originally recorded for the potential assessment of interest associated with a customer advance. This amount was partially offset by expenses related to recovery from Hurricane Katrina. In 2004, the increase in total other income and expense compared to 2003 was due to interest rates on long-term debt decreasing and lower principal amount of debt outstanding.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. PEP is based on annual projected costs, including estimates for inflation. When historical costs are included, or when inflation exceeds projected costs used in rate regulation, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. The inflation rate has been relatively low in recent years and any adverse effect of inflation on the Company has not been significant.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and wholesale customers in the southeastern United States. Prices for electricity relating to purchased power agreements, interconnecting transmission lines and the exchange of electric power are regulated by the FERC. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges and risks of the Company's business of selling electricity. These factors include the ability of the Company to maintain a stable regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon growth in energy sales, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth in the Company's service area in the aftermath of Hurricane Katrina.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental regulations could affect earnings if such costs cannot be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental regulations are modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging violations of the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric), including one co-owned by the Company. The civil actions requested penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

The EPA has issued a series of proposed and final revisions to its NSR regulations under the Clean Air Act, many of which have been subject to legal challenges by environmental groups and states. On June 24, 2005, the U.S. Court of Appeals for the District of Columbia Circuit upheld, in part, the EPA's revisions to NSR regulations that were issued in December 2002 but vacated portions of those revisions addressing the exclusion of certain pollution control projects. The Mississippi Department of Environmental Quality (MDEQ) formally adopted the 2002 NSR rules effective in July 2005, but did not adopt the provisions vacated by the District of Columbia Circuit. On March 17, 2006, the U.S. Court of Appeals for the District of Columbia Circuit also vacated an EPA rule which sought to clarify the scope of the existing Routine Maintenance, Repair and Replacement exclusion. In October 2005 and September 2006, the EPA also published proposed rules clarifying the test for determining when an emissions increase subject to the NSR permitting requirements has occurred. The impact of these proposed rules will depend on adoption of the final rules by the EPA and the State of Mississippi's implementation of such rules, as well as the outcome of any additional legal challenges, and, therefore, cannot be determined at this time.

Carbon Dioxide Litigation

In July 2004, attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed a complaint in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. A nearly identical complaint was filed by three environmental groups in the same court. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. Plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005. The ultimate outcome of these matters cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; and the Endangered Species Act.

Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through the Company's Environmental Compliance Overview Plan (ECO) Plan. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information. Through 2006, the Company had invested approximately $144.0 million in capital projects to comply with these requirements, with annual totals of $4.8 million, $4.0 million, and $2.9 million for 2006, 2005, and 2004, respectively. The Company expects that capital expenditures to assure compliance with existing and new regulations will be an additional $21.0 million, $91.1 million, and $81.8 million for 2007, 2008, and 2009, respectively. Because the Company's compliance strategy is impacted by changes to existing environmental laws and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix, the ultimate outcome cannot be determined at this time. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2006, the Company had spent approximately $77.5 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act.

In 2005, the EPA revoked the one-hour ozone air quality standard and published the second of two sets of final rules for implementation of the new, more stringent eight-hour ozone standard. During 2005, the EPA's fine particulate matter nonattainment designations also became effective for several areas across the United States. No areas within the Company's service area, however, have been designated as nonattainment under either the eight-hour ozone standard or the fine particulate matter standard.

The EPA issued the final Clean Air Interstate Rule in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities or by the purchase of emission allowances from a cap-and-trade program.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air

Visibility Rule allows states to determine that the Clean Air Interstate Rule satisfies BART requirements for SO_2 and NO_x. However, additional BART requirements for particulate matter could be imposed, and the reasonable progress provisions could result in requirements for additional SO_2 controls. By December 17, 2007, states must submit implementation plans that contain strategies for BART and any other control measures required to achieve the first phase of reasonable progress.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. The Company anticipates that emission controls installed to achieve compliance with the Clean Air Interstate Rule and the eight-hour ozone and fine-particulate air quality standards will also result in mercury emission reductions. However, the long-term capability of emission control equipment to reduce mercury emissions is still being evaluated, and the installation of additional control technologies may be required.

The impacts of the eight-hour ozone and the fine particulate matter nonattainment designations, the Clean Air Interstate Rule, the Clean Air Visibility Rule, and the Clean Air Mercury Rule on the Company will depend on the development and implementation of rules at the state level. States implementing the Clean Air Mercury Rule and the Clean Air Interstate Rule, in particular, have the option not to participate in the national cap-and-trade programs and could require reductions greater than those mandated by the federal rules. Impacts will also depend on resolution of pending legal challenges to these rules. Therefore, the full effects of these regulations on the Company cannot be determined at this time. The Company has developed and continually updates a comprehensive environmental compliance strategy to comply with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2, NO_x, and mercury emission controls within the next several years to assure continued compliance with applicable air quality requirements.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot now be determined.

One facility within the Southern Company system is retrofitting a closed-loop recirculating cooling tower under the Clean Water Act to cool water prior to discharge and similar projects are being considered at other facilities.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and release of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in the financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. The Company has received authority from the Mississippi PSC to recover approved environmental compliance costs through specific retail rate clauses. Within limits approved by the Mississippi PSC, these rates are adjusted annually. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" and "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Global Climate Issues

Domestic efforts to limit greenhouse gas emissions have been spurred by international negotiations under the Framework Convention on Climate Change and specifically the Kyoto Protocol, which proposes a binding limitation on the emissions of greenhouse gases for industrialized countries. The Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other mandatory carbon dioxide reduction legislation; however, in 2002, it did announce a goal to reduce the greenhouse gas intensity of the U.S. economy, the ratio of greenhouse gas emissions to the value of U.S. economic output, by 18 percent by 2012. Southern Company is participating in the voluntary electric utility sector climate change initiative, known as Power Partners, under the Bush Administration's Climate VISION program. The utility sector pledged to reduce its greenhouse gas emissions rate by 3 percent to 5 percent by 2010-2012. Southern Company continues to evaluate future energy and emission profiles relative to the Power Partners program and is participating in voluntary programs to support the industry initiative. In addition, Southern Company is participating in the Bush Administration's Asia Pacific Partnership on Clean Development and Climate, a public/private partnership to work together to meet goals for energy security, national air pollution reduction, and climate change in ways that promote sustainable economic growth and poverty reduction. Legislative proposals that would impose mandatory restrictions on carbon dioxide emissions continue to be considered in Congress. The ultimate outcome cannot be determined at this time; however, mandatory restrictions on the Company's carbon dioxide emissions could result in significant additional compliance costs that could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $8.4 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $14.5 million for the Company, of which $7.3 million relates to sales inside the retail service territory as discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, Gulf Power, the Company, Savannah Electric, Southern Power, and Southern Company Services, Inc. (SCS) as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due to Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Transmission

In December 1999, the FERC issued its final rule on Regional Transmission Organizations (RTOs). Since that time, there have been a number of additional proceedings at the FERC designed to encourage further voluntary formation of RTOs or to mandate their formation. However, at the current time, there are no active proceedings that would require the Company to participate in an RTO. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. See "Market-Based Rate Authority" and "Generation Interconnection Agreements" above for additional information. The final outcome of these proceedings cannot now be determined. However, the Company's financial condition, results of operations, and cash flows could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

PSC Matters

Performance Evaluation Plan

See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for information on the Company's base rates. In May 2004, the Mississippi PSC approved the Company's request to reclassify 266 megawatts of Plant Daniel Units 3 and 4 capacity to jurisdictional cost of service effective January 1, 2004, and authorized the Company to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. The Company is amortizing the regulatory liability established pursuant to the Mississippi PSC's order to earnings as follows: $16.5 million in 2004, $25.1 million in 2005, $13.0 million in 2006, and $5.7 million in 2007, resulting in reductions of costs in each of those years.

In December 2006, the Company submitted its annual PEP filing for 2007, which resulted in no rate change. Pursuant to the PEP rate schedule, an order is not required from the Mississippi PSC for the Company to continue to bill the filed rate in effect. In March 2006, the Mississippi PSC approved the Company's 2006 PEP filing, which included an annual retail base rate increase of 5 percent, or $32 million, that was effective in April 2006. Ordinarily, PEP limits annual rate increases to 4 percent; however, the Company had requested that the Mississippi PSC approve a temporary change to allow it to exceed this cap as a result of the ongoing effects of Hurricane Katrina.

System Restoration Rider

In September 2006, the Company filed with the Mississippi PSC a request to implement a System Restoration Rider (SRR) to increase the Company's cap on the property damage reserve and to authorize the calculation of an annual property damage accrual based on a formula. The purpose of the SRR is to provide for recovery of costs associated with property damage (property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Company would be required to make annual SRR filings to determine the revenue requirement associated with any property damage. The Company recorded a regulatory liability in the amount of approximately $2.4 million in 2006 for the estimated amount due to retail customers that would be passed through SRR. In February 2007, the Company received an order from the Mississippi PSC approving the SRR.

Environmental Compliance Overview Plan

In February 2007, the Company filed with the Mississippi PSC its annual Environmental Compliance Overview (ECO) Plan evaluation for 2007. The Company requested an 86 cent per 1,000 KWH increase for retail customers. This increase represents approximately $7.5 million in annual revenues for the Company. Hearings with the Mississippi PSC are expected to be held in April 2007. In April 2006 the Mississippi PSC approved the Company's 2006 ECO Plan, which included a 12 cent per 1,000 KWH reduction for retail customers. This decrease represented a reduction of approximately $1.3 million in annual revenues for the Company. The new rates were effective in April 2006. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information. The outcome of the 2007 filing cannot now be determined.

Fuel Cost Recovery

The Company establishes annually a fuel cost recovery factor that is approved by the Mississippi PSC. Over the past two years, the Company has continued to experience higher than expected fuel costs for coal and natural gas. The Company is required to file for an adjustment to the fuel cost recovery factor annually; such filing occurred in November 2006. As a result, the Mississippi PSC approved an increase in the fuel cost recovery factor effective January 2007 in an amount equal to 4.6 percent of total retail revenues. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this increase to the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

Storm Damage Cost Recovery

In August 2005, Hurricane Katrina hit the Gulf Coast of Mississippi and caused significant damage within the Company's service area. The Company maintains a reserve for property damage to cover the cost of damage from major storms to its transmission and distribution lines and the cost of uninsured damage to its generation facilities and other property. A 1999 Mississippi PSC order allowed the Company to accrue $1.5 million to $4.6 million to the reserve annually, with a maximum reserve totaling $23 million. In October 2006, in conjunction with the Hurricane Katrina-related financing order, the Mississippi PSC ordered the Company to cease all accruals to the retail property damage reserve until a new reserve cap is established. However, in the same financing order, the Mississippi PSC approved the replenishment of the property damage reserve with $60 million to be funded with a portion of the proceeds of bonds to be issued by the Mississippi Development Bank on behalf of the State of Mississippi and reported as liabilities by the State of Mississippi.

In June 2006, the Mississippi PSC issued an order based upon a stipulation between the Company and the Mississippi Public Utilities Staff. The stipulation and the associated order certified actual storm restoration costs relating to Hurricane Katrina through April 30, 2006, of $267.9 million and affirmed estimated additional costs through December 31, 2007, of $34.5 million, for total storm restoration costs of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million. Of the total amount, $292.8 million applies to the Company's retail jurisdiction. The order directed the Company to file an application with the MDA for a CDBG.

The Company filed the CDBG application with the MDA in September 2006. On October 30, 2006, the Company received from the MDA a CDBG in the amount of $276.4 million. The Company has appropriately allocated and applied these CDBG proceeds to both retail and wholesale storm restoration cost recovery. The retail portion of $267.6 million was applied to the retail regulatory asset in the balance sheets. For the remaining wholesale portion of $8.8 million, $3.3 million was credited to operations and maintenance expense in the statements of income and $5.5 million was applied to accumulated provision for depreciation in the balance sheets. The CDBG proceeds related to capital of

$152.7 million and $120.3 million related to retail operations and maintenance expense are included in the statements of cash flows as separate line items. The cash portions of storm costs are included in the statements of cash flows under Hurricane Katrina accounts payable, property additions, and cost of removal, net of salvage and totaled approximately $50.5 million, $54.2 million, and $4.6 million, respectively, for 2006 and totaled approximately $82.1 million, $81.7 million, and $18.4 million, respectively, for 2005.

The balance in the retail regulatory asset account at December 31, 2006, was $4.7 million, which is net of the retail portion of insurance proceeds of $80.9 million, CDBG proceeds of $267.6 million, and tax credits of $0.3 million. Retail costs incurred through December 31, 2006 include approximately $148.1 million of capital and $124.5 million of operations and maintenance expenditures. Of the $302.4 million total storm costs affirmed by the Mississippi PSC, the Company has incurred total storm costs of $280.5 million as of December 31, 2006.

The Company filed an application for a financing order with the Mississippi PSC on July 3, 2006 for system restoration costs under the state bond program. On October 27, 2006, the Mississippi PSC issued a financing order that authorizes the issuance of $121.2 million of system restoration bonds. This amount includes $25.2 million for the retail storm recovery costs not covered by the CDBG, $60 million for a property damage reserve, and $36 million for the retail portion of the construction of the storm operations facility. The bonds will be issued by the Mississippi Development Bank on behalf of the State of Mississippi and will be reported as liabilities by the State of Mississippi. Periodic true-up mechanisms will be structured to comply with terms and requirements of the legislation. Details regarding the issuance of the bonds have not been finalized. The final outcome of this matter cannot now be determined.

The Mississippi PSC order also granted continuing authority to record a regulatory asset in an amount equal to the retail portion of the recorded Hurricane Katrina restoration costs. For any future event causing damage to property beyond the balance in the reserve, the order also granted the Company the authority to record a regulatory asset. The Company would then apply to the Mississippi PSC for recovery of such amounts or for authority to otherwise dispose of the regulatory asset. The Company continues to report actual storm expenses to the Mississippi PSC periodically.

See Notes 1 and 3 to the financial statements under "Provision for Property Damage" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Other Matters

In June 2006, the Company filed an application with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The proposed project is an advanced coal gasification facility located in Kemper County, Mississippi that would use locally mined lignite coal. The proposed 693 megawatt plant, excluding the mine cost, is expected to require an approximate investment of $1.5 billion and is expected to be completed in 2013. The DOE subsequently certified the project and in November 2006, the Internal Revenue Service (IRS) allocated Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A tax credits to the Company of $133 million. The utilization of these credits is dependent upon meeting the certification requirements for the project under the Internal Revenue Code. The plant would use an air-blown integrated gasification combined cycle technology that generates power from low-rank coals and coals with high moisture or high ash content. These coals, which include lignite, make up half the proven U.S. and worldwide coal reserves. The Company is still undergoing a feasibility assessment of the project which could take up to two years. On December 21, 2006, the Mississippi PSC approved the Company's request for accounting treatment of the costs associated with the Company's generation resource planning, evaluation, and screening activities. The Mississippi PSC gave the Company the authority to create and recognize a regulatory asset for such costs. The Company estimates that in order to reach the next major milestone in the evaluation process, it may spend up to $12 million by the third quarter of 2007. These costs will be charged to and remain as a regulatory asset until the Mississippi PSC determines the prudence and ultimate recovery of such costs either in conjunction with a certificate proceeding filed by the Company for approval of its next generating asset or by June 30, 2008, which ever occurs first. The balance of such regulatory asset will be included in the Company's rate base for ratemaking purposes. Approval by various regulatory agencies, including the Mississippi PSC, will also be required if the project proceeds. The final outcome of this matter cannot now be determined.

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

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a loss is considered probable and reasonably estimable in accordance with generally accepted accounting principles. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, or the EPA.

Unbilled Revenues

Revenues related to the sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Plant Daniel Operating Lease

As discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units," the Company leases a 1,064 megawatt natural gas combined cycle facility at Plant Daniel (Facility) from Juniper Capital L.P. (Juniper). For both accounting and rate recovery purposes, this transaction is treated as an operating lease, which means that the related obligations under this agreement are not reflected in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements" herein for further information. The operating lease determination was based on assumptions and estimates related to the following:

- Fair market value of the Facility at lease inception.
- The Company's incremental borrowing rate.
- Timing of debt payments and the related amortization of the initial acquisition cost during the initial lease term.
- Residual value of the Facility at the end of the lease term.
- Estimated economic life of the Facility.
- Juniper's status as a voting interest entity.

The determination of operating lease treatment was made at the inception of the lease agreement and is not subject to change unless subsequent changes are made to the agreement. However the Company also is required to monitor Juniper's ongoing status as a voting interest entity. Changes in that status could require the Company to consolidate the Facility's assets and the related debt and to record interest and depreciation expense of approximately $37 million annually, rather than annual lease expense of approximately $27 million.

New Accounting Standards

Stock Options

On January 1, 2006, the Company adopted FASB Statement No. 123(R), "Share-Based Payment," using the modified prospective method. This statement requires that compensation cost relating to share-based payment transactions be recognized in financial statements. That cost is measured based on the grant date fair value of the equity or liability instruments issued. Although the compensation expense required under the revised statement differs slightly, the impacts on the Company's financial statements are similar to the pro forma disclosures included in Note 1 to the financial statements under "Stock Options."

Pensions and Other Postretirement Plans

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $21.3 million with respect to its overfunded defined benefit plan and additional liabilities of $1.5 million and $29.1 million, respectively, related to its underfunded non-qualified pension plans and other postretirement benefit plans. Additionally, SFAS No. 158 will require the Company to change the measurement date for its defined benefit postretirement plan assets and obligations from September 30 to December 31 beginning with the year ending December 31, 2008. See Note 2 to the financial statements for additional information.

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007. The adoption of FIN 48 did not have a material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157), in September 2006. SFAS No. 157 provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2006. Net cash flow from operations increased from 2005 by $153.0 million. The increase was primarily due to the proceeds received from the CDBG program. The $77.4 million decrease in 2005 compared to 2004 resulted primarily from the storm damage costs related to Hurricane Katrina. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" for additional information.

Significant changes in the balance sheet as of December 31, 2006, compared to 2005, primarily relate to Hurricane Katrina storm restoration activities. These storm-related changes include a reduction in the retail regulatory asset primarily as a result of the CDBG proceeds of $267.6 million, the decrease in insurance receivable primarily as a result of the receipt of external insurance proceeds of $58 million, a reduction to affiliated payables in the amount of $98.3 million primarily due to the payment of storm-related charges, and a reduction in notes payable in the amount of $151 million. Additional changes include a $54.7 million decrease in under recovered regulatory clause revenues primarily due to fuel cost recovery in 2006. For additional information regarding significant changes in the balance sheets, see Note 2 to the financial statements under "Retirement Benefits." See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Recovery" for additional information related to the deferral of the restoration costs, including both capital and operation and maintenance expenditures.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, increased from 64.3 percent in 2005 to 65.4 percent at December 31, 2006. The Company has received investment grade ratings from the major rating agencies with respect to debt, preferred securities, and preferred stock.

Sources of Capital

The Company plans to obtain the funds required for construction, continued storm damage restoration, and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, and short-term borrowings. See Note 3 to the financial statements under "Storm Damage Cost Recovery" for additional information. The amount, type, and timing of any financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amount of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

To meet short-term cash needs and contingencies, the Company has various sources of liquidity. At December 31, 2006, the Company had approximately $4.2 million of cash and cash equivalents and $181 million of unused credit arrangements with banks. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. At December 31, 2006, the Company had $51.4 million outstanding in commercial paper.

Financing Activities

During 2006, a portion of the CDBG funds was used to repay short-term debt incurred to fund storm restoration efforts.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Off-Balance Sheet Financing Arrangements

In 2001, the Company began an initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel. In June 2003, the Company entered into a restructured lease agreement for the Facility with Juniper, as discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units." Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50 percent of Juniper's assets. The Company does not consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. Accordingly, the lease is not reflected in the balance sheets.

The initial lease term ends in 2011, and the lease includes a renewal and a purchase option based on the cost of the Facility at the inception of the lease, which was approximately $370 million. The Company is required to amortize approximately four percent of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, the Company may elect to renew for 10 years. If the lease is renewed, the agreement calls for the Company to amortize an additional 17 percent of the initial completion cost over the renewal period. Upon termination of the lease, at the Company's option, it may either exercise its purchase option or the Facility can be sold to a third party.

The lease also provides for a residual value guarantee, approximately 73 percent of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, the Company, along with all members of the Southern Company power pool, is party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for Alabama Power and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million.

Market Price 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 manage the volatility attributable to these exposures, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

The Company does not currently hedge interest rate risk. The weighted average interest rate on variable long-term debt at January 1, 2007 was 4.41 percent. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $1.2 million at December 31, 2006. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term.

See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. At December 31, 2006, exposure from these activities was not material to the Company's financial statements.

In addition, at the instruction of the Mississippi PSC, the Company has implemented a fuel-hedging program. At December 31, 2006, exposure from these activities was not material to the Company's financial statements.

The changes in fair value of energy contracts and year-end valuations were as follows:

	Changes in Fair Value	
	2006	2005
	(in thousands)	
Contracts beginning of year	$ 27,106	$ 889
Contracts realized or settled	(494)	(13,816)
New contracts at inception	-	-
Changes in valuation techniques	-	-
Current period changes(a)	(32,972)	40,033
Contracts end of year	$ (6,360)	$ 27,106

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

Source of 2006 Year-End Valuation Prices

	Total Fair Value	Maturity Year 1	2-3 Years
	(in thousands)		
Actively quoted	$(7,506)	$(6,065)	$(1,441)
External sources	1,146	1,146	-
Models and other methods	-	-	-
Contracts end of year	$(6,360)	$(4,919)	$(1,441)

These contracts are related primarily to fuel hedging programs under which unrealized gains and losses from mark to market adjustments are recorded as regulatory assets and liabilities. Realized gains and losses from these programs are included in fuel expense and are recovered through the Company's energy cost management clause.

Gains and losses on forward contracts for the sale of electricity that do not represent hedges are recognized in the statements of income as incurred. For the years ended December 31, 2006, 2005, and 2004, these amounts were not material.

At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$(7,321)
Accumulated other comprehensive income	969
Net income	(8)
Total fair value	$(6,360)

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented. The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $146 million for 2007, of which $6 million is related to Hurricane Katrina restoration, $258 million for 2008, and $161 million for 2009. Environmental expenditures included in these amounts are $21 million, $91 million, and $82 million for 2007, 2008, and 2009, respectively. Actual construction costs may vary from this estimate because of changes in such factors as: business conditions; environmental regulations; FERC rules and regulations; load projections; storm impacts; 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.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Mississippi PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments, are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in thousands)		
Long-term debt[a] –					
Principal	$ -	$ 40,000	$ -	$238,777	$ 278,777
Interest	14,694	29,388	24,956	278,796	347,834
Commodity derivative obligations[b]	8,572	2,681	-	-	11,253
Preferred stock dividends[c]	1,733	3,466	3,466	-	8,665
Operating leases	40,095	71,592	59,721	3,574	174,982
Purchase commitments[d]					
Capital[e]	146,000	419,000	-	-	565,000
Coal	280,602	271,185	35,100	31,200	618,087
Natural gas[f]	140,242	193,531	70,171	248,697	652,641
Long-term service agreements	10,547	20,768	21,765	101,856	154,936
Post retirement benefits trust[g]	190	380	-	-	570
Total	$642,675	$1,051,991	$215,179	$902,900	$2,812,745

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2007, as reflected in the statements of capitalization.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2006, 2005, and 2004 were $237 million, $240 million, and $237 million, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program.

(f) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2006.

(g) The Company forecasts postretirement trust contributions over a three-year period. No contributions related to the Company's pension trust are currently expected during this period. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning growth, retail rates, storm damage cost recovery and repairs, fuel cost recovery, environmental regulations and expenditures, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax, 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, regulatory investigations, proceedings, or inquiries, including FERC matters and EPA civil actions;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- 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 ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

For the Years Ended December 31, 2006, 2005, and 2004
Mississippi Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 647,186**	$618,860	$584,313
Sales for resale –			
Non-affiliates	**268,850**	283,413	265,863
Affiliates	**76,439**	50,460	44,371
Other revenues	**16,762**	17,000	15,779
Total operating revenues	**1,009,237**	969,733	910,326
Operating Expenses:			
Fuel	**438,622**	358,572	324,882
Purchased power –			
Non-affiliates	**16,292**	32,208	33,528
Affiliates	**56,955**	111,284	73,235
Other operations –			
Other	**170,277**	168,355	160,477
Maintenance	**66,415**	71,267	77,001
Depreciation and amortization	**46,853**	33,549	39,390
Taxes other than income taxes	**60,904**	60,058	55,572
Total operating expenses	**856,318**	835,293	764,085
Operating Income	**152,919**	134,440	146,241
Other Income and (Expense):			
Interest income	**4,272**	1,718	777
Interest expense	**(16,041)**	(11,230)	(11,776)
Interest expense to affiliate trust	**(2,598)**	(2,598)	(1,948)
Distributions on mandatorily redeemable preferred securities	**-**	-	(630)
Other income (expense), net	**(6,712)**	(415)	(1,365)
Total other income and (expense)	**(21,079)**	(12,525)	(14,942)
Earnings Before Income Taxes	**131,840**	121,915	131,299
Income taxes	**48,097**	46,374	50,666
Net Income	**83,743**	75,541	80,633
Dividends on Preferred Stock	**1,733**	1,733	3,832
Net Income After Dividends on Preferred Stock	**$ 82,010**	$ 73,808	$ 76,801

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

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2006, 2005, and 2004
Mississippi Power Company 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 83,743**	$ 75,541	$ 80,633
Adjustments to reconcile net income to net cash provided from operating activities --			
Depreciation and amortization	**68,198**	63,319	60,260
Deferred income taxes and investment tax credits, net	**(47,535)**	118,316	44,424
Plant Daniel capacity	**(13,008)**	(25,125)	(16,508)
Pension, postretirement, and other employee benefits	**5,650**	2,938	(1,084)
Stock option expense	**1,057**	-	-
Tax benefit of stock options	**258**	3,723	1,532
Other, net	**(5,761)**	1,493	(1,823)
Changes in certain current assets and liabilities --			
Receivables	**64,976**	(107,836)	(26,250)
Fossil fuel stock	**7,765**	(25,745)	5,528
Materials and supplies	**750**	(6,234)	(3,768)
Prepaid income taxes	**20,247**	(40,059)	3,419
Other current assets	**(6,560)**	(2,498)	(2,018)
Hurricane Katrina grant proceeds	**120,328**	-	-
Hurricane Katrina accounts payable	**(50,512)**	(82,102)	-
Other accounts payable	**(30,419)**	40,255	(5,555)
Accrued taxes	**1,972**	4,001	151
Accrued compensation	**(629)**	674	82
Over recovered regulatory clause revenues	**(26,188)**	20,831	(25,761)
Other current liabilities	**634**	441	6,052
Net cash provided from operating activities	**194,966**	41,933	119,314
Investing Activities:			
Property additions	**(127,290)**	(158,084)	(72,066)
Cost of removal net of salvage	**(9,420)**	(26,140)	(3,189)
Construction payables	**(7,596)**	16,417	1,243
Hurricane Katrina capital grant proceeds	**152,752**	-	-
Other	**(1,992)**	(2,655)	(2,066)
Net cash provided from (used for) investing activities	**6,454**	(170,462)	(76,078)
Financing Activities:			
Increase (decrease) in notes payable, net	**(150,746)**	202,124	-
Proceeds--			
Senior notes	**-**	30,000	40,000
Preferred stock	**-**	-	30,000
Gross excess tax benefit of stock options	**669**	-	-
Capital contributions from parent company	**5,503**	(25)	1,791
Redemptions--			
First mortgage bonds	**-**	(30,000)	-
Senior notes	**-**	-	(80,000)
Preferred stock	**-**	-	(28,388)
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,829)
Payment of common stock dividends	**(65,200)**	(62,000)	(66,200)
Other	**-**	(2,481)	(785)
Net cash provided from (used for) financing activities	**(211,507)**	135,885	(105,411)
Net Change in Cash and Cash Equivalents	**(10,087)**	7,356	(62,175)
Cash and Cash Equivalents at Beginning of Year	**14,301**	6,945	69,120
Cash and Cash Equivalents at End of Year	**$ 4,214**	$ 14,301	$ 6,945
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $–, $– and $– capitalized, respectively)	**$ 29,288**	$ 13,499	$ 12,084
Income taxes (net of refunds)	**75,209**	(40,801)	6,654

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

BALANCE SHEETS

At December 31, 2006 and 2005
Mississippi Power Company 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 4,214**	$ 14,301
Receivables --		
Customer accounts receivable	**42,099**	36,747
Unbilled revenues	**23,807**	20,267
Under recovered regulatory clause revenues	**50,778**	105,505
Other accounts and notes receivable	**5,870**	21,507
Insurance receivable	**20,551**	60,163
Affiliated companies	**23,696**	19,595
Accumulated provision for uncollectible accounts	**(855)**	(2,321)
Fossil fuel stock, at average cost	**42,679**	50,444
Materials and supplies, at average cost	**27,927**	28,678
Prepaid income taxes	**22,031**	42,278
Other regulatory assets	**42,391**	23,042
Other	**15,091**	25,160
Total current assets	**320,279**	445,366
Property, Plant, and Equipment:		
In service	**2,054,151**	1,987,294
Less accumulated provision for depreciation	**836,922**	803,754
	1,217,229	1,183,540
Construction work in progress	**40,608**	52,225
Total property, plant, and equipment	**1,257,837**	1,235,765
Other Property and Investments	**4,636**	6,821
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**9,280**	9,863
Prepaid pension costs	**36,424**	17,264
Deferred property damage	**-**	209,324
Other regulatory assets	**61,086**	22,241
Other	**18,834**	34,625
Total deferred charges and other assets	**125,624**	293,317
Total Assets	**$1,708,376**	$1,981,269

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

BALANCE SHEETS
At December 31, 2006 and 2005
Mississippi Power Company 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Notes payable	**$ 51,377**	$ 202,124
Accounts payable --		
Affiliated	**24,615**	122,899
Other	**73,236**	89,598
Customer deposits	**8,676**	7,298
Accrued taxes --		
Income taxes	**4,171**	17,736
Other	**50,346**	48,296
Accrued interest	**2,332**	3,408
Accrued compensation	**23,958**	24,587
Over recovered regulatory clause revenues	**-**	26,188
Plant Daniel capacity	**5,659**	13,008
Other	**40,266**	40,334
Total current liabilities	**284,636**	595,476
Long-term Debt (See accompanying statements)	**242,553**	242,548
Long-term Debt Payable to Affiliated Trust (See accompanying statements)	**36,082**	36,082
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**236,202**	266,629
Deferred credits related to income taxes	**16,218**	19,003
Accumulated deferred investment tax credits	**16,402**	17,465
Employee benefit obligations	**92,403**	58,318
Other cost of removal obligations	**82,397**	81,284
Other regulatory liabilities	**22,559**	13,411
Other	**56,324**	57,113
Total deferred credits and other liabilities	**522,505**	513,223
Total Liabilities	**1,085,776**	1,387,329
Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**589,820**	561,160
Total Liabilities and Stockholder's Equity	**$1,708,376**	$1,981,269
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION

At December 31, 2006 and 2005
Mississippi Power Company 2006 Annual Report

	2006	2005	2006	2005
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
5.4% to 5.625% due 2033-2035	**$120,000**	$120,000		
Adjustable rates (5.54% at 1/1/07) due 2009	**40,000**	40,000		
Total long-term notes payable	**160,000**	160,000		
Other long-term debt --				
Pollution control revenue bonds:				
Variable rates (3.75% to 4.04% at 1/1/07) due 2020-2028	**82,695**	82,695		
Unamortized debt premium (discount), net	**(142)**	(147)		
Total long-term debt (annual interest requirement -- $12.1 million)	**242,553**	242,548	**27.0%**	27.8%
Long-term Debt Payable to Affiliated Trust:				
7.20% due 2041 (annual interest requirement -- $2.6 million)	**36,082**	36,082	**4.0**	4.1
Cumulative Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25% (annual dividend requirement -- $1.7 million)	**32,780**	32,780	**3.6**	3.8
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**307,019**	299,536		
Retained earnings	**244,511**	227,701		
Accumulated other comprehensive income (loss)	**599**	(3,768)		
Total common stockholder's equity	**589,820**	561,160	**65.4**	64.3
Total Capitalization	**$901,235**	$872,570	**100.0%**	100.0%

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2006, 2005, and 2004
Mississippi Power Company 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$37,691	$292,841	$203,419	$(1,462)	$532,489
Net income after dividends on preferred stock	-	-	76,801	-	76,801
Capital contributions from parent company	-	3,323	-	-	3,323
Other comprehensive income (loss)	-	-	-	(2,122)	(2,122)
Cash dividends on common stock	-	-	(66,200)	-	(66,200)
Other	-	(327)	1,873	-	1,546
Balance at December 31, 2004	37,691	295,837	215,893	(3,584)	545,837
Net income after dividends on preferred stock	-	-	73,808	-	73,808
Capital contributions from parent company	-	3,699	-	-	3,699
Other comprehensive income (loss)	-	-	-	(184)	(184)
Cash dividends on common stock	-	-	(62,000)	-	(62,000)
Balance at December 31, 2005	**37,691**	**299,536**	**227,701**	**(3,768)**	**561,160**
Net income after dividends on preferred stock	**-**	**-**	**82,010**	**-**	**82,010**
Capital contributions from parent company	**-**	**7,483**	**-**	**-**	**7,483**
Other comprehensive income (loss)	**-**	**-**	**-**	**(180)**	**(180)**
Adjustment to initially apply FASB Statement No. 158, net of tax	**-**	**-**	**-**	**4,547**	**4,547**
Cash dividends on common stock	**-**	**-**	**(65,200)**	**-**	**(65,200)**
Balance at December 31, 2006	**$37,691**	**$307,019**	**$244,511**	**$ 599**	**$589,820**

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Mississippi Power Company 2006 Annual Report

	2006	2005	2004
Net income after dividends on preferred stock	**$82,010**	$73,808	$76,801
Other comprehensive income (loss):			
Change in additional minimum pension liability, net of tax of $(614), $(167) and $(1,131), respectively	**(990)**	(269)	(1,825)
Change in fair value of marketable securities, net of tax of $-, $- and $49, respectively	**-**	-	80
Changes in fair value of qualifying hedges, net of tax of $502, $53 and $(184), respectively	**810**	85	(297)
Less: Reclassification adjustment for amounts included in net income, net of tax of $-, $- and $(49), respectively	**-**	-	(80)
Total other comprehensive income (loss)	**(180)**	(184)	(2,122)
Comprehensive Income	**$81,830**	$73,624	$74,679

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom, and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power, Georgia Power, Gulf Power, and the Company, provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing service to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, and manages generation assets, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. On January 4, 2006, Southern Company completed the sale of substantially all of the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The equity method is used for subsidiaries which are variable interest entities and for which the Company is not the primary beneficiary. Certain prior years' data presented in the financial statements have been reclassified to conform with the current year presentation.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its 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.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $55.2 million, $51.6 million, and $45.3 million during 2006, 2005, and 2004, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. However, with the hurricane damage experienced in the last two years, assistance for storm restoration has caused an increase in these activities. The total amount of storm restoration provided to Alabama Power, Georgia Power, and Gulf Power in 2004 and 2005 was $3.3 million and $1.0 million, respectively. These activities were billed at cost. The Company received storm restoration assistance from other Southern Company subsidiaries totaling $1.5 million and $73.5 million in 2006 and 2005, respectively.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of all associated expenditures and costs. The Company reimbursed Alabama Power for the Company's proportionate share of related expenses which totaled $8.6 million, $8.2 million, and $7.2 million in 2006, 2005, and 2004, respectively. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs. Gulf Power reimbursed the Company for Gulf Power's proportionate share of related expenses which totaled $19.7 million, $19.5 million, and $17.4 million in 2006, 2005, and 2004, respectively. See Notes 4 and 5 for additional information on certain deferred tax liabilities payable to affiliates.

In 2006, for purposes of filing the consolidated Southern Company tax return, the Company treated certain items as tax capital gains rather than deferring those gains over the life of the related assets. This allowed two Southern Holdings entities to utilize certain tax capital losses in the current year rather than carry them forward to future years. The Company has recorded a deferred tax liability of approximately $22.8 million related to these Southern Holdings entities in "Accumulated Deferred Income Taxes" on the balance sheets.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

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" (SFAS No. 71). 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:

	2006	2005	Note
	(in thousands)		
Hurricane Katrina	**$ 4,683**	$209,324	(i)
Underfunded retiree benefit plans	**38,814**	-	(j)
Property damage	**(4,356)**	(500)	(g)
Deferred income tax charges	**9,860**	10,443	(a)
Property tax	**18,264**	15,148	(b)
Vacation pay	**7,078**	6,954	(c)
Loss on reacquired debt	**9,626**	10,381	(d)
Loss on redeemed preferred stock	**743**	914	(e)
Loss on rail cars	**344**	405	
Other regulatory assets	**4,798**	-	(g)
Fuel-hedging assets	**12,252**	232	(f)
Asset retirement obligations	**6,954**	10,668	(a)
Deferred income tax credits	**(18,238)**	(20,559)	(a)
Other cost of removal obligations	**(82,397)**	(81,284)	(a)
Plant Daniel capacity	**(5,659)**	(18,667)	(h)
Fuel-hedging liabilities	**(3,644)**	(27,695)	(f)
Other liabilities	**(2,606)**	(660)	(g)
Overfunded retiree benefit plans	**(21,319)**	-	(j)
Total	**$(24,803)**	$115,104	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Recovered over the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(e) Amortized over a period beginning in 2004 that is not to exceed seven years.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, costs are recovered through the Energy Cost Management clause (ECM).

(g) Recorded and recovered as approved by the Mississippi PSC.

(h) Amortized over a four-year period ending in 2007.

(i) For additional information, see Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery."

(j) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 under "Retirement Benefits."

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS 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, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery."

Government Grants

The Company received a grant in October 2006 from the Mississippi Development Authority (MDA) for $276.4 million, primarily for storm damage cost recovery. The grant proceeds do not represent a future obligation of the Company. The portion of any grants received related to retail storm recovery is applied to the retail regulatory asset that is established as restoration costs are incurred. The portion related to wholesale storm recovery is recorded either as a reduction to operations and maintenance expense or as a reduction in accumulated depreciation depending on the restoration work performed and the appropriate allocations of cost of service.

Revenues

Energy and other revenues are recognized as services are rendered. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

The Company has a diversified base of customers. For years ended December 31, 2006 and December 31, 2005, no single customer or industry comprises 10 percent or more of revenue. For all periods presented, uncollectible accounts averaged less than 1 percent of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes the cost of purchased emission allowances as they are used. Fuel costs also included gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other 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 life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction for projects over $10 million.

The Company's property, plant, and equipment consisted of the following at December 31:

	2006	2005
	(in thousands)	
Generation	**$ 847,904**	$ 833,598
Transmission	**414,490**	390,961
Distribution	**648,304**	624,769
General	**143,453**	137,966
Total plant in service	**$2,054,151**	$1,987,294

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.2 percent in 2006 and 3.4 percent in each of 2005 and 2004. Depreciation studies are conducted periodically to update the composite rates. In March 2006, the Mississippi PSC approved the study filed by the Company in 2005, with new rates effective January 1, 2006. The new depreciation rates did not result in a material change to annual depreciation expense. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost, together with the cost of removal, less salvage, is charged to the accumulated depreciation provision. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation expense includes an amount for the expected cost of removal of facilities.

In January 2006, the Mississippi PSC issued an accounting order directing the Company to exclude from its calculation of depreciation expense approximately $1.2 million related to capitalized Hurricane Katrina costs since these costs will be recovered separately.

In December 2003, the Mississippi PSC issued an interim accounting order directing the Company to expense and record a regulatory liability of $60.3 million while it considered the Company's request to include 266 megawatts of Plant Daniel Units 3 and 4 generating capacity in jurisdictional cost of service. In May 2004, the Mississippi PSC approved the Company's request effective January 1, 2004 and ordered the Company to amortize the regulatory liability previously established to reduce depreciation and amortization expenses as follows: $16.5 million in 2004, $25.1 million in 2005, $13.0 million in 2006, and $5.7 million in 2007.

Asset Retirement Obligations and Other Costs of Removal

Effective January 1, 2003, the Company adopted FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143), which established new accounting and reporting standards for legal obligations associated with the ultimate cost of retiring long-lived assets. The present value of the ultimate cost of an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In addition, effective December 31, 2005, the Company adopted the provisions of FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" (FIN 47), which requires that an asset retirement obligation be recorded even though the timing and/or method of settlement are conditional on future events. Prior to December 2005, the Company did not recognize asset retirement obligations for asbestos removal and disposal of polychlorinated biphenyls in certain transformers because the timing of their retirements was dependent on future events. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability. Therefore, the Company had no cumulative effect to net income resulting from the adoption of SFAS No. 143 or FIN 47.

The Company has retirement obligations related to various landfill sites and underground storage tanks. In connection with the adoption of FIN 47, the Company also recorded additional asset retirement obligations (and assets) of $9.5 million, primarily related to asbestos. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under SFAS No. 143 and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2006	2005
	(in millions)	
Balance, beginning of year	**$15.4**	$ 5.5
Liabilities incurred	**-**	9.5
Liabilities settled	**(0.1)**	-
Accretion	**0.8**	0.4
Cash flow revisions	**(0.3)**	-
Balance, end of year	**$15.8**	$15.4

Impairment of Long-Lived Assets and Intangibles

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

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to a regulatory liability account. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. A 1999 Mississippi PSC order allowed the Company to accrue $1.5 million to $4.6 million to the reserve annually, with a maximum reserve totaling $23 million. In October 2006, in conjunction with the Mississippi PSC Hurricane Katrina-related financing order, the Mississippi PSC ordered the Company to cease all accruals to the retail property damage reserve until a new reserve cap is established. However, in the same financing order, the Mississippi PSC approved the replenishment of the property damage reserve with $60 million to be funded with a portion of the proceeds of bonds to be issued by the Mississippi Development Bank on behalf of the State of Mississippi and reported as liabilities by the State of Mississippi. The Company accrued $1.2 million in 2006, $1.5 million in 2005, and $4.6 million in 2004. The Company made no discretionary accruals in 2006 as a result of the order. See Note 3 under "Storm Damage Cost Recovery" and "System Restoration Rider" for additional information regarding the depletion of these reserves following Hurricane Katrina and the deferral of additional costs, as well as additional rate riders or other cost recovery mechanisms which have and/or may be approved by the Mississippi PSC to replenish these reserves.

Environmental Cost Recovery

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through retail rates. In February 2007, the Company filed with the Mississippi PSC its annual Environmental Compliance Overview (ECO) Plan evaluation for 2007. The Company requested an 86 cent per 1,000 kilowatt-hour (KWH) increase for retail customers. This increase represents approximately $7.5 million in annual revenues for the Company. Hearings with the Mississippi PSC are expected to be held in April 2007. In April 2006 the Mississippi PSC approved the Company's 2006 ECO Plan, which included a 12 cent per 1,000 KWH reduction for retail customers. This decrease represented a reduction of approximately $1.3 million per year in annual revenues for Mississippi Power. The new rates were effective in April 2006. The outcome of the 2007 filing cannot now be determined.

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 average 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 or used.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Mississippi PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Stock Options

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. Prior to January 1, 2006, the Company accounted for options granted in accordance with Accounting Principles Board Opinion No. 25; thus, no compensation expense was recognized because the exercise price of all options granted equaled the fair market value on the date of the grant.

Effective January 1, 2006, the Company adopted the fair value recognition provisions of FASB Statement No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified prospective method. Under that method, compensation cost for the year ended December 31, 2006 is recognized as the requisite service is rendered and includes: (a) compensation cost for the portion of share-based awards granted prior to and that were outstanding as of January 1, 2006, for which the requisite service had not been rendered, based on the grant-date fair value of those awards as calculated in accordance with the original provisions of FASB Statement No. 123, "Accounting for Stock-based Compensation" (SFAS No. 123), and (b) compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123(R). Results for prior periods have not been restated.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

For the Company, the adoption of SFAS No. 123(R) has resulted in a reduction in earnings before income taxes and net income of $1.1 million and $0.7 million, respectively, for the year ended December 31, 2006.

Additionally, SFAS No. 123(R) requires the gross excess tax benefit from stock option exercises to be reclassified as a financing cash flow as opposed to an operating cash flow; the reduction in operating cash flows and increase in financing cash flows for the year ended December 31, 2006 was $0.7 million.

For the years prior to the adoption of SFAS No. 123(R), the pro forma impact on net income of fair-value accounting for options granted is as follows:

Net Income	As Reported	Option Impact After Tax	Pro Forma
	(in thousands)		
2005	$73,808	$(648)	$73,160
2004	76,801	(682)	76,119

Because historical forfeitures have been insignificant and are expected to remain insignificant, no forfeitures are assumed in the calculation of compensation expense; rather they are recognized when they occur.

The estimated fair values of stock options granted in 2006, 2005, and 2004 were derived using the Black-Scholes stock option pricing model. Expected volatility is based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company uses historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Period ended December 31	2006	2005	2004
Expected volatility	**16.9%**	17.9%	19.6%
Expected term (in years)	**5.0**	5.0	5.0
Interest rate	**4.6%**	3.9%	3.1%
Dividend yield	**4.4%**	4.4%	4.8%
Weighted average grant-date fair value	**$4.15**	$3.90	$3.29

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in the prices of certain fuel purchases and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value.

Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, as appropriate until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income.

The Mississippi PSC has approved the Company's request to implement an ECM which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

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 financial instruments for which the carrying amounts did not equal the fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2006	**$278,635**	**$275,745**
2005	278,630	273,278

The fair values were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and changes in the additional minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Mandatorily Redeemable Preferred Securities/Long-Term Debt Payable to Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investments in this trust are reflected as Other Investments and the related loan from the trust is reflected as Long-term Debt Payable to Affiliated Trust in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2007. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the Mississippi PSC and the FERC. For the year ending December 31, 2007, postretirement trust contributions are expected to total approximately $0.2 million.

On December 31, 2006, the Company adopted FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), which requires recognition of the funded status of its defined benefit postretirement plans in its balance sheet. Prior to the adoption of SFAS No. 158, the Company generally recognized only the difference between the benefit expense recognized and employer contributions to the plan as either a prepaid asset or as a liability. With respect to its underfunded non-qualified pension plan, the Company recognized an additional minimum liability representing the difference between each plan's accumulated benefit obligation and its assets.

With the adoption of SFAS No. 158, the Company was required to recognize on its balance sheet previously unrecognized assets and liabilities related to unrecognized prior service cost, unrecognized gains or losses (from changes in actuarial assumptions and the difference between actual and expected returns on plan assets), and any unrecognized transition amounts (resulting from the change from cash-basis accounting to accrual accounting). These amounts will continue to be amortized as a component of expense over the employees' remaining average service life as SFAS No. 158 did not change the recognition of pension and other postretirement benefit expense in the statements of income. With the adoption of SFAS No. 158, the Company recorded an additional prepaid pension asset of $21.3 million with respect to its overfunded defined benefit plan and additional liabilities of $1.5 million and $29.1 million, respectively, related to its underfunded non-qualified pension plans and retiree benefit plans.

The incremental effect of applying SFAS No. 158 on individual line items in the balance sheet at December 31, 2006 follows:

	Before	Adjustments	After
	(in millions)		
Prepaid pension costs	$ 15	$ 21	$ 36
Other regulatory assets	22	39	61
Other property and investments	6	(1)	5
Total assets	1,649	59	1,708
Accumulated deferred income taxes	(234)	(2)	(236)
Other regulatory liabilities	(2)	(21)	(23)
Employee benefit obligations	(61)	(31)	(92)
Total liabilities	(1,031)	(54)	(1,085)
Accumulated other comprehensive income	4	(5)	(1)
Total stockholders' equity	(618)	(5)	(623)

Because the recovery of postretirement benefit expense through rates is considered probable, the Company recorded offsetting regulatory assets or regulatory liabilities under the provisions of SFAS No. 71 with respect to the prepaid assets and the liabilities.

The measurement date for plan assets and obligations is September 30 for each year presented. Pursuant to SFAS No. 158, the Company will be required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008.

Pension Plans

The total accumulated benefit obligation for the pension plans was $233 million and $235 million for 2006 and 2005, respectively. Changes during the year in the projected benefit obligations and fair value of plan assets were as follows:

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$255,037	$232,658
Service cost	7,207	6,566
Interest cost	13,727	13,089
Benefits paid	(11,288)	(10,703)
Actuarial loss and employee transfers	(13,987)	12,080
Amendments	(153)	1,347
Balance at end of year	250,543	255,037
Change in plan assets		
Fair value of plan assets at beginning of year	246,271	222,543
Actual return on plan assets	30,304	33,654
Employer contributions	1,308	1,206
Benefits paid	(11,288)	(10,703)
Employee transfers	681	(429)
Fair value of plan assets at end of year	267,276	246,271
Funded status at end of year	16,733	(8,766)
Unrecognized transition amount	-	(545)
Unrecognized prior service cost	-	14,288
Unrecognized net loss	-	3,449
Fourth quarter contributions	433	465
Prepaid pension asset, net	$ 17,166	$ 8,891

At December 31, 2006, the projected benefit obligations for the qualified and non-qualified pension plans were $230.9 million and $19.7 million, respectively. All plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	36%	**38%**	40%
International equity	24	**23**	24
Fixed income	15	**16**	17
Real estate	15	**16**	13
Private equity	10	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plan consist of the following:

	2006	2005
	(in thousands)	
Prepaid pension costs	**$ 36,424**	$ 17,264
Other regulatory assets	**9,707**	-
Current liabilities, other	**(1,209)**	-
Other regulatory liabilities	**(21,319)**	-
Employee benefit obligations	**(18,049)**	(16,357)
Other property and investments	**-**	2,224
Accumulated other comprehensive income	**-**	5,760

Presented below are the amounts included in accumulated other comprehensive income, regulatory assets, and regulatory liabilities at December 31, 2006, related to the defined benefit pension plans that have not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss
Balance at December 31, 2006:	(in thousands)	
Regulatory asset	$ 798	$ 8,909
Regulatory liabilities	11,488	(32,807)
Total	$12,286	$(23,898)

Estimated amortization in net periodic pension cost in 2007:

	Prior Service Cost	Net (Gain)/ Loss
	(in thousands)	
Regulatory asset	$ 214	$658
Regulatory liabilities	1,277	-
Total	$1,491	$658

Components of net periodic pension cost (income) were as follows:

	2006	2005	2004
	(in thousands)		
Service cost	**$ 7,207**	$ 6,566	$ 6,153
Interest cost	**13,727**	13,089	12,249
Expected return on plan assets	**(18,107)**	(18,437)	(18,325)
Recognized net (gain) loss	**773**	526	865
Net amortization	**1,013**	937	(361)
Net periodic pension cost (income)	**$ 4,613**	$ 2,681	$ 581

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2006, estimated benefit payments were as follows:

	(in thousands)
2007	$11,286
2008	11,532
2009	11,989
2010	12,374
2011	12,862
2012 to 2016	77,477

Other Postretirement Benefits

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

	2006	2005
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	$ 86,482	$ 75,435
Service cost	1,520	1,427
Interest cost	4,654	4,242
Benefits paid	(3,836)	(3,937)
Actuarial (gain) loss	596	9,315
Retiree drug subsidy	257	-
Balance at end of year	89,673	86,482
Change in plan assets		
Fair value of plan assets at beginning of year	22,759	20,183
Actual return on plan assets	2,290	2,462
Employer contributions	3,652	4,051
Benefits paid	(5,012)	(3,937)
Fair value of plan assets at end of year	23,689	22,759
Funded status at end of year	(65,984)	(63,723)
Unrecognized transition amount	-	2,543
Unrecognized prior service cost	-	1,398
Unrecognized net loss	-	26,919
Fourth quarter contributions	1,421	902
Accrued liability (recognized in the balance sheet)	$(64,563)	(31,961)

Other postretirement benefits plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2006	2005
Domestic equity	28%	30%	31%
International equity	19	18	18
Fixed income	33	34	36
Real estate	12	13	10
Private equity	8	5	5
Total	100%	100%	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2006	2005
	(in thousands)	
Regulatory assets	$ 29,107	$ -
Employee benefit obligations	(64,563)	(31,961)

Presented below are the amounts included in accumulated other comprehensive income and regulatory assets at December 31, 2006, related to the other postretirement benefit plans that have not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for the next fiscal year.

	Prior Service Cost	Net (Gain)/ Loss	Transition Obligation
		(in thousands)	
Balance at December 31, 2006:			
Regulatory asset	$1,293	$25,618	$2,196
Estimated amortization as net periodic postretirement benefit cost in 2007:			
Regulatory asset	$106	$1,190	$346

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

	2006	2005	2004
		(in thousands)	
Service cost	$ 1,520	$ 1,427	$ 1,330
Interest cost	4,654	4,242	4,015
Expected return on plan assets	(1,642)	(1,563)	(1,716)
Transition obligation	346	346	346
Prior service cost	106	106	106
Recognized net loss	1,250	706	408
Net postretirement cost	$ 6,234	$ 5,264	$ 4,489

In the third quarter 2004, the Company prospectively adopted FASB Staff Position 106-2, "Accounting and Disclosure Requirements" (FSP 106-2), related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act). The Medicare Act provides a 28 percent prescription drug subsidy for Medicare eligible retirees. FSP 106-2 requires recognition of the impacts of the Medicare Act in the APBO and future cost of service for postretirement medical plan. The effect of the subsidy reduced the Company's expenses for the six months ended December 31, 2004 and for the years ended December 31, 2005 and 2006 by approximately $0.5 million, $1.2 million, and $2.0 million, respectively, and is expected to have a similar impact on future expenses.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2007	$ 3,878	$ (366)	$ 3,512
2008	4,253	(431)	3,822
2009	4,628	(499)	4,129
2010	5,036	(565)	4,471
2011	5,370	(644)	4,726
2012 to 2016	31,526	(4,510)	27,016

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs for 2004 were calculated using a discount rate of 6.00 percent.

	2006	2005	2004
Discount	**6.00%**	5.50%	5.75%
Annual salary increase	**3.50**	3.00	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.56 percent for 2007, decreasing gradually to 5.00 percent through the year 2015, 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 APBO and the service and interest cost components at December 31, 2006 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	**$6,552**	**$5,567**
Service and interest costs	**393**	**350**

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to six percent of the employee's base salary. Total matching contributions made to the plan for 2006, 2005, and 2004 were $3.0 million, $2.9 million, and $2.8 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power (including a facility formerly owned by Savannah Electric), including one co-owned by the Company. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

On June 19, 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization and formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. On August 14, 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to Plants Barry, Gaston, Gorgas, and Greene County. The plaintiffs have appealed this decision to the U.S. Court of Appeals for the Eleventh Circuit and, on November 14, 2006, the Eleventh Circuit granted plaintiffs' request to stay the appeal, pending the U.S. Supreme Court's ruling in a similar NSR case filed by the EPA against Duke Energy. The action against Georgia Power has been administratively closed since the spring of 2001, and none of the parties has sought to reopen the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $32,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in any one of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Environmental Remediation

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is now in bankruptcy and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. Amounts expensed during 2004, 2005, and 2006 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final outcome of this matter to the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties and cannot now be determined. The remediation expenses incurred by the Company are expected to be recovered through the ECO Plan.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $8.4 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $14.5 million for the Company, of which $7.3 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, Gulf Power, the Company, Savannah Electric, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated and, in particular, the propriety of the continued inclusion of Southern Power as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The impact of the modifications is not expected to have a material impact on the Company's financial statements.

Generation Interconnection Agreements

In July 2003, the FERC issued its final rule on the standardization of generation interconnection agreements and procedures (Order 2003). Order 2003 shifts much of the financial burden of new transmission investment from the generator to the transmission provider. The FERC has indicated that Order 2003, which was effective January 20, 2004, is to be applied prospectively to new generating facilities interconnecting to a transmission system. Order 2003 was affirmed by the U.S. Court of Appeals for the District of Columbia Circuit on January 12, 2007. The cost impact resulting from Order 2003 will vary on a case-by-case basis for each new generator interconnecting to the transmission system.

On November 22, 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities, with interest. Southern Company has also received requests for similar modifications from other entities, though no other complaints are pending with the FERC. On January 19, 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order requires the modification of Tenaska's interconnection agreements, the order reduces the amount of the refund that had been requested by Tenaska. As a result, Southern Company estimates indicate that no refund is due to Tenaska. Southern Company has requested rehearing of the FERC's order. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Georgia Power, Gulf Power, and Southern Telecom, have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of the Company believes that it has complied with applicable laws and that the plaintiffs' claims are without merit.

To date, the Company has entered into agreements with plaintiffs in approximately 90 percent of the actions pending against the Company to clarify the Company's easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit) and dismissals of the related cases are in progress. These agreements have not had any material impact on the Company's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, Georgia Power, Gulf Power, the Company, Savannah Electric, and Southern Telecom, were named as defendants in a lawsuit brought by a telecommunications company that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Retail Regulatory Matters

Performance Evaluation Plan

The Company's retail base rates are set under Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective that PEP would reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In May 2004, the Mississippi PSC approved the Company's request to modify certain portions of its PEP and to reclassify, to jurisdictional cost of service the 266 megawatts of Plant Daniel Units 3 and 4 capacity, effective January 1, 2004. The Mississippi PSC authorized the Company to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. The Company is amortizing the regulatory liability established pursuant to the Mississippi PSC's interim December 2003 accounting order, as approved in the May 2004 order, to earnings as follows: \$16.5 million in 2004, \$25.1 million in 2005, \$13.0 million in 2006, and \$5.7 million in 2007, resulting in increases to earnings in each of those years.

In addition, the Mississippi PSC also approved the Company's requested changes to PEP, including the use of a forward-looking test year, with appropriate oversight; annual, rather than semi-annual, filings; and certain changes to the performance indicator mechanisms. Rate changes will be limited to four percent of retail revenues annually under the revised PEP. The Mississippi PSC will review all aspects of PEP in 2007. PEP will remain in effect until the Mississippi PSC modifies, suspends, or terminates the plan.

In March 2006, the Mississippi PSC approved the Company's 2006 PEP filing, which included an annual retail base rate increase of 5 percent, or \$32 million, to be effective in April 2006. Ordinarily, PEP limits annual rate increases to 4 percent; however, the Company had requested that the Mississippi PSC approve a temporary change to allow it to exceed this cap as a result of the ongoing effects of Hurricane Katrina.

In December 2006, the Company submitted its annual PEP filing for 2007, which resulted in no rate change. Pursuant to the PEP rate schedule, an order is not required from the Mississippi PSC for the Company to continue to bill the filed rate in effect.

System Restoration Rider

In September 2006, the Company filed with the Mississippi PSC a request to implement a System Restoration Rider (SRR), to increase the Company's cap on the property damage reserve and to authorize the calculation of an annual property damage accrual based on a formula. The purpose of the SRR is to provide for recovery of costs associated with property damage (property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Company would be required to make annual SRR filings to determine the revenue requirement associated with the property damage. The Company recorded a regulatory liability in the amount of approximately $2.4 million in 2006 for the estimated amount due to retail customers that would be passed through SRR. In February 2007, the Company received an order from the Mississippi PSC approving the SRR.

Environmental Compliance Overview Plan

The ECO Plan establishes procedures to facilitate the Mississippi PSC's overview of the Company's environmental strategy and provides for recovery of costs (including cost of capital) associated with environmental projects approved by the Mississippi PSC. Under the ECO Plan, any increase in the annual revenue requirement is limited to two percent of retail revenues. However, the ECO Plan also provides for carryover of any amount over the two percent limit into the next year's revenue requirement. The Company conducts studies, when possible, to determine the extent of any required environmental remediation. Should such remediation be determined to be probable, reasonable estimates of costs to clean up such sites are developed and recognized in the financial statements. In accordance with the Mississippi PSC order, the Company recovers such costs under the ECO Plan as they are incurred.

In February 2007, the Company filed with the Mississippi PSC its annual ECO Plan evaluation for 2007. The Company requested an 86 cent per 1,000 KWH increase for retail customers. This increase represents approximately $7.5 million in annual revenues for the Company. Hearings with the Mississippi PSC are expected to be held in April 2007. In April 2006 the Mississippi PSC approved the Company's 2006 ECO Plan, which included a 12 cent per 1,000 KWH reduction for retail customers. This decrease represented a reduction of approximately $1.3 million in annual revenues for the Company. The new rates were effective in April 2006. The outcome of the 2007 filing cannot now be determined.

Storm Damage Cost Recovery

In August 2005, Hurricane Katrina hit the Gulf Coast of the United States and caused significant damage within the Company's service area. The Company maintains a reserve to cover the cost of damage from major storms to its transmission and distribution facilities and the cost of uninsured damage to its generation facilities and other property. A 1999 Mississippi PSC order allowed the Company to accrue $1.5 million to $4.6 million to the reserve annually, with a maximum reserve totaling $23 million. In October 2006, in conjunction with the Mississippi PSC Hurricane Katrina-related financing order, the Mississippi PSC ordered the Company to cease all accruals to the retail property damage reserve, until a new reserve cap is established. However, in the same financing order, the Mississippi PSC approved the replenishment of the property damage reserve with $60 million to be funded with a portion of the proceeds of bonds to be issued by the Mississippi Development Bank on behalf of the State of Mississippi and reported as liabilities by the State of Mississippi.

In June 2006, the Mississippi PSC issued an order based upon a stipulation between the Company and the Mississippi Public Utilities Staff. The stipulation and the associated order certified actual storm restoration costs relating to Hurricane Katrina through April 30, 2006 of $267.9 million and affirmed estimated additional costs through December 31, 2007 of $34.5 million, for total storm restoration costs of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million. Of the total amount, $292.8 million applies to the Company's retail jurisdiction. The order directed the Company to file an application with the MDA for a Community Development Block Grant (CDBG).

The Company filed the CDBG application with the MDA in September 2006. On October 30, 2006, the Company received from the MDA a CDBG in the amount of $276.4 million. The Company has appropriately allocated and applied these CDBG proceeds to both retail and wholesale storm restoration cost recovery. The retail portion of $267.6 million was applied to the retail regulatory asset in the balance sheets. For the remaining wholesale portion of $8.8 million, $3.3 million was credited to operations and maintenance expense in the statements of income, and $5.5 million was applied to accumulated provision for depreciation in the balance sheets. The CDBG proceeds related to capital of $152.7 million and $120.3 million related to retail operations and maintenance expense are included in the statement of cash flows as separate line items. The cash portions of storm costs are included in the statements of cash flows under Hurricane Katrina accounts payable, property additions, and cost of removal, net of salvage and totaled approximately $50.5 million, $54.2 million, and $4.6 million, respectively, for 2006 and totaled approximately $82.1 million, $81.7 million, and $18.4 million, respectively, for 2005.

The balance in the retail regulatory asset account at December 31, 2006, was $4.7 million, which is net of the retail portion of insurance proceeds of $80.9 million, CDBG proceeds of $267.6 million, and tax credits of $0.3 million. Retail costs incurred through December 31, 2006, include approximately $148.1 million of capital and $124.5 million of operations and maintenance expenditures. Of the $302.4 million total storm costs affirmed by the Mississippi PSC, the Company has incurred total storm costs of $280.5 million as of December 31, 2006.

The Company filed an application for a financing order with the Mississippi PSC on July 3, 2006 for system restoration costs under the state bond program. On October 27, 2006, the Mississippi PSC issued a financing order that authorizes the issuance of $121.2 million of system restoration bonds. This amount includes $25.2 million for the retail storm recovery costs not covered by the CDBG, $60 million for a property damage reserve, and $36 million for the retail portion of the construction of the storm operations facility. The bonds will be issued by the Mississippi Development Bank on behalf of the State of Mississippi and will be reported as liabilities by the State of Mississippi. Periodic true-up mechanisms will be structured to comply with terms and requirements of the legislation. Details regarding the issuance of the bonds have not been finalized. The final outcome of this matter cannot now be determined.

The Mississippi PSC order also granted continuing authority to record a regulatory asset in an amount equal to the retail portion of the recorded Hurricane Katrina restoration costs. For any future event causing damage to property beyond the balance in the reserve, the order also granted the Company the authority to record a regulatory asset. The Company would then apply to the Mississippi PSC for recovery of such amounts or for authority to otherwise dispose of the regulatory asset. The Company continues to report actual storm expenses to the Mississippi PSC periodically.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 with a total capacity of 500 megawatts at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 with a total capacity of 1,000 megawatts at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2006, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

Generating Plant	Percent Ownership	Gross Investment	Accumulated Depreciation
		(in thousands)	
Greene County Units 1 and 2	40%	$ 75,668	$ 42,813
Daniel Units 1 and 2	50%	$263,566	$130,025

The Company's proportionate share of plant operating expenses is included in the statements of income.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the State of Alabama and the State of Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

At December 31, 2006, the tax-related regulatory assets and liabilities were $9.9 million and $18.2 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 the current enacted tax law and to unamortized investment tax credits.

Details of the income tax provisions were as follows:

	2006	2005	2004
	(in thousands)		
Federal —			
Current	$ 79,332	$ (61,933)	$ 3,700
Deferred	(36,889)	102,659	40,350
	42,443	40,726	44,050
State —			
Current	16,300	(10,009)	2,542
Deferred	(10,646)	15,657	4,074
	5,654	5,648	6,616
Total	$ 48,097	$ 46,374	$50,666

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:

	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	$259,729	$269,188
Basis differences	13,615	8,630
Fuel clause under recovered	9,660	41,627
Regulatory assets associated with asset retirement obligations	6,324	6,162
Regulatory assets associated with employee benefit obligations	19,695	-
Other	42,142	59,883
Total	351,165	385,490
Deferred tax assets:		
Federal effect of state deferred taxes	11,252	13,642
Other property basis differences	8,538	9,244
Pension and other benefits	35,210	13,473
Property insurance	1,646	3,618
Unbilled fuel	8,812	7,660
Other comprehensive loss	(388)	2,441
Asset retirement obligations	6,324	6,162
Regulatory liabilities associated with employee benefit obligations	8,154	-
Other	31,244	44,961
Total	110,792	101,201
Total deferred tax liabilities, net	240,373	284,289
Portion included in accrued income taxes, net	(4,171)	(17,660)
Accumulated deferred income taxes in the balance sheets	$236,202	$266,629

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.1 million for 2006 and $1.2 million for each of 2005 and 2004. At December 31, 2006, all investment tax credits available to reduce federal income taxes payable had been utilized.

In 2006, for purposes of filing the consolidated Southern Company tax return, the Company treated certain items as tax capital gains rather than deferring those gains over the life of the related assets. This allowed two Southern Holdings entities to utilize certain tax capital losses in the current year rather than carry them forward to future years. The Company has recorded a deferred tax liability of approximately $22.8 million related to these Southern Holdings entities in "Accumulated Deferred Income Taxes" in the balance sheets.

The provision for income taxes differs from the amount of income taxes determined by applying the applicable U.S. federal statutory rate to earnings before income taxes and preferred dividends as a result of the following:

	2006	2005	2004
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	3.0	3.0	3.3
Non-deductible book: Depreciation	0.3	0.5	0.4
Other	(2.0)	(0.5)	(0.1)
Effective income tax rate	36.3%	38.0%	38.6%

6. FINANCING

Mandatorily Redeemable Preferred Securities/ Long-Term Debt Payable to Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investment and preferred security sale were loaned back to the Company through the issuance of junior subordinated notes totaling $36 million, which constitute substantially all of the assets of the trust and are reflected in the balance sheets as Long-term Debt Payable to Affiliated Trust (including Securities Due Within One Year). The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2006, preferred securities of $35 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for the trust and the related securities.

Pollution Control Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2006, was $82.7 million.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, depositary preferred stock (each share of depositary preferred stock representing one-fourth of a share of preferred stock), and common stock outstanding. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock and depositary preferred stock are subject to redemption at the option of the Company on or after a specified date.

Bank Credit Arrangements

At the beginning of 2007, the Company had total unused committed credit agreements with banks of $181 million. Of the total, $101 million expires in 2007 and $80 million in 2008. The facilities contain $39 million 2-year term loan options and $15 million 1-year term loan options. The Company expects to renew its credit facilities, as needed, prior to expiration.

In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees are ⅛ of 1 percent or less for the Company. Compensating balances are not legally restricted from withdrawal.

This $181 million in unused credit arrangements provides required liquidity support to the Company's borrowings through a commercial paper program. At December 31, 2006, the Company had $51.4 million outstanding in commercial notes. The credit arrangements also provide support to the Company's variable daily rate tax-exempt pollution control bonds totaling $40.1 million.

During 2006, the peak amount outstanding for short-term debt was $372.3 million and the average amount outstanding was $256.8 million. The average annual interest rate on short-term debt was 5.19 percent for 2006 and 3.85 percent for 2005.

Financial Instruments

The Company also enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented fuel-hedging programs with the approval of the Mississippi PSC. The Company enters into hedges of forward electricity sales. There was no material ineffectiveness recorded in earnings in 2006, 2005, or 2004.

At December 31, 2006, the fair value gains/(losses) of energy-related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Regulatory assets, net	$(7,321)
Accumulated other comprehensive income	969
Net income	(8)
Total fair value	$(6,360)

The fair value gains or losses for cash flow hedges are recorded as regulatory assets and liabilities if they are recoverable through the regulatory clauses, otherwise they are recorded in other comprehensive income, and are recognized in earnings at the same time the hedged items affect earnings. For the year 2007, approximately $1.0 million of pre-tax gains are expected to be reclassified from other comprehensive income to fuel expense. The Company has energy-related hedges in place up to and including 2009.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $146 million in 2007, of which $6 million is related to Hurricane Katrina restoration, $258 million in 2008, and $161 million in 2009. The construction program is subject to periodic review and revision, and actual construction costs may vary from the above estimates because of numerous factors. These factors include changes in business conditions; acquisition of additional generation assets; revised load growth estimates; changes in environmental regulations; changes in FERC rules and regulations; increasing costs of labor, equipment, and materials; and cost of capital. At December 31, 2006, significant purchase commitments were outstanding in connection with the construction program. The Company has no generating plants under construction. Capital improvements to generating, transmission, and distribution facilities, including those to meet environmental standards, will continue.

Long-Term Service Agreements

The Company has entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the leased combined cycle units at Plant Daniel. The LTSA provides that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, the LTSA is in effect through two major inspection cycles of the units. Scheduled payments to GE are made monthly based on estimated operating hours of the units and are recognized as expense based on actual hours of operation. The Company has recognized $8.4 million, $7.9 million, and $9.0 million for 2006, 2005, and 2004, respectively, which is included in maintenance expense in the statements of income. Remaining payments to GE under this agreement are currently estimated to total $154 million over the next 13 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has entered into a LTSA with ABB Power Generation Inc. (ABB) for the purpose of securing maintenance support for its Chevron Unit 5 combustion turbine plant. In summary, the LTSA stipulates that ABB will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. ABB is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, this LTSA is in effect through two major inspection cycles. Scheduled payments to ABB are made at various intervals based on actual operating hours of the unit. Payments to ABB under this agreement are currently estimated to total $0.6 million over the remaining term of the agreement, which is approximately three months. However, the LTSA contains various cancellation provisions at the option of the Company. Payments made to ABB prior to the performance of any planned maintenance are recorded as a prepayment in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed. After this contract expires, the Company expects to replace it with a new contract with similar terms.

Fuel Commitments

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery. Amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2006.

Total estimated minimum long-term obligations at December 31, 2006 were as follows:

Year	Natural Gas	Coal
	(in thousands)	
2007	$140,242	$280,602
2008	112,049	222,905
2009	81,482	48,280
2010	50,612	19,500
2011	19,559	15,600
2012 and thereafter	248,697	31,200
Total commitments	$652,641	$618,087

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

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

Railcar Leases

The Company and Gulf Power have jointly entered into operating lease agreements for the use of 745 aluminum railcars. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company also has multiple operating lease agreements for the use of an additional 120 aluminum railcars that do not contain a purchase option. All of these leases are for the transport of coal to Plant Daniel.

The Company's share (50 percent) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $4.6 million in 2006, $3.0 million in 2005, and $1.9 million in 2004. The Company's annual lease payments for 2007 through 2011 will average approximately $2.4 million and after 2012, lease payments total in aggregate approximately $3.6 million.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50 percent at Plant Daniel and 100 percent at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.9 million in 2006 and $0.6 million in 2005. The Company's annual lease payments for 2007 through 2011 will average approximately $0.5 million. The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $4.9 million in 2006 related to barges and tow/shift boats. The Company's annual lease payments for 2007 through 2009, with regards to these barge transportation leases, will average approximately $4.9 million.

Plant Daniel Combined Cycle Generating Units

In May 2001, the Company began the initial 10-year term of the lease agreement for a 1,064 megawatt natural gas combined cycle generating facility built at Plant Daniel (Facility). The Company entered into this transaction during a period when retail access was under review by the Mississippi PSC. The lease arrangement provided a lower cost alternative to its cost based rate regulated customers than a traditional rate base asset. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for a description of the Company's formula rate plan.

In 2003, the Facility was acquired by Juniper Capital L.P. (Juniper), whose partners are unaffiliated with the Company. Simultaneously, Juniper entered into a restructured lease agreement with the Company. Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50 percent of Juniper's assets. The Company is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease agreement is treated as an operating lease for accounting purposes, as well as for both retail and wholesale rate recovery purposes. For income tax purposes, the Company retains tax ownership. The initial lease term ends in 2011 and the lease includes a purchase and renewal option based on the cost of the Facility at the inception of the lease, which was $370 million. The Company is required to amortize approximately four percent of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, the Company may elect to renew for 10 years. If the lease is renewed, the agreement calls for the Company to amortize an additional 17 percent of the initial completion cost over the renewal period. Upon termination of the lease, at the Company's option, it may either exercise its purchase option or the Facility can be sold to a third party.

The lease provides for a residual value guarantee, approximately 73 percent of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility. A liability of approximately $9 million and $11 million for the fair market value of this residual value guarantee is included in the balance sheets at December 31, 2006 and 2005, respectively. Lease expenses were $27 million, $27 million, and $25 million in 2006, 2005, and 2004, respectively.

The Company estimates that its annual amount of future minimum operating lease payments under this arrangement, exclusive of any payment related to the residual value guarantee, as of December 31, 2006, are as follows:

Year	Lease Payments
	(in thousands)
2007	$ 28,718
2008	28,615
2009	28,504
2010	28,398
2011	28,291
2012 and thereafter	-
Total commitments	$142,526

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2006, there were 272 current and former employees of the Company participating in the stock option plan. The maximum number of shares of Southern Company common stock that may be issued under these programs may not exceed 57 million. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting. As part of the adoption of SFAS No. 123(R), as discussed in Note 1 under "Stock Options," Southern Company has not modified its stock option plan or outstanding stock options, nor has it changed the underlying valuation assumptions used in valuing the stock options that were used under SFAS No. 123.

The Company's activity in the stock option plan for 2006 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2005	1,444,438	$26.86
Granted	254,135	33.81
Exercised	(214,761)	22.95
Cancelled	(569)	32.71
Outstanding at December 31, 2006	**1,483,243**	**$28.62**
Exercisable at December 31, 2006	**1,007,549**	**$26.68**

The number of stock options vested and expected to vest in the future as of December 31, 2006, is not significantly different from the number of stock options outstanding at December 31, 2006 as stated above.

As of December 31, 2006, the weighted average remaining contractual term for the options outstanding and options exercisable is 6.1 years and 5.0 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable is $12.2 million and $10.3 million, respectively.

As of December 31, 2006, there was $0.4 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $2.4 million, $4.3 million, and $2.3 million, respectively.

The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $0.9 million, $1.7 million, and $0.9 million, respectively, for the years ended December 31, 2006, 2005, and 2004.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2006 and 2005 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends On Preferred Stock
	(in thousands)		
March 2006	**$208,941**	**$28,728**	**$15,282**
June 2006	**254,920**	**40,392**	**22,766**
September 2006	**310,747**	**62,215**	**36,638**
December 2006	**234,629**	**21,584**	**7,324**
March 2005	$215,216	$31,904	$16,947
June 2005	248,576	43,059	25,632
September 2005	277,907	51,975	28,244
December 2005	228,034	7,502	2,985

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

	2006	2005	2004	2003	2002
Operating Revenues (in thousands)	$ 1,009,237	$ 969,733	$ 910,326	$ 869,924	$ 824,165
Net Income after Dividends on Preferred Stock (in thousands)	$ 82,010	$ 73,808	$ 76,801	$ 73,499	$ 73,013
Cash Dividends on Common Stock (in thousands)	$ 65,200	$ 62,000	$ 66,200	$ 66,000	$ 63,500
Return on Average Common Equity (percent)	14.25	13.33	14.24	13.99	14.46
Total Assets (in thousands)	$ 1,708,376	$ 1,981,269	$ 1,479,113	$ 1,511,174	$ 1,482,040
Gross Property Additions (in thousands)	$ 127,290	$ 158,084	$ 70,063	$ 69,345	$ 67,460
Capitalization (in thousands):					
Common stock equity	$ 589,820	$ 561,160	$ 545,837	$ 532,489	$ 517,953
Preferred stock	32,780	32,780	32,780	31,809	31,809
Mandatorily redeemable preferred securities	-	-	-	35,000	35,000
Long-term debt payable to affiliated trust	36,082	36,082	36,082	-	-
Long-term debt	242,553	242,548	242,498	202,488	243,715
Total (excluding amounts due within one year)	$ 901,235	$ 872,570	$ 857,197	$ 801,786	$ 828,477
Capitalization Ratios (percent):					
Common stock equity	65.4	64.3	63.7	66.4	62.5
Preferred stock	3.6	3.8	3.8	4.0	3.8
Mandatorily redeemable preferred securities	-	-	-	4.4	4.2
Long-term debt payable to affiliated trust	4.0	4.1	4.2	-	-
Long-term debt	27.0	27.8	28.3	25.2	29.5
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds –					
Moody's	-	-	Aa3	Aa3	Aa3
Standard and Poor's	-	-	A+	A+	A+
Fitch	-	-	AA	AA-	AA-
Preferred Stock –					
Moody's	A3	A3	A3	A3	A3
Standard and Poor's	BBB+	BBB+	BBB+	BBB+	BBB+
Fitch	A+	A+	A+	A	A
Unsecured Long-Term Debt –					
Moody's	A1	A1	A1	A1	A1
Standard and Poor's	A	A	A	A	A
Fitch	AA-	AA-	AA-	A+	A+
Customers (year-end):					
Residential	147,643	142,077	160,189	159,582	158,873
Commercial	32,958	30,895	33,646	33,135	32,713
Industrial	507	512	522	520	489
Other	177	176	183	171	171
Total	181,285	173,660	194,540	193,408	192,246
Employees (year-end)	1,270	1,254	1,283	1,290	1,301

SELECTED FINANCIAL AND OPERATING DATA 2002-2006
Mississippi Power Company 2006 Annual Report (continued)

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Residential	**$ 214,472**	$ 209,546	$ 199,242	$ 180,978	$ 186,522
Commercial	**215,451**	213,093	199,127	175,416	181,224
Industrial	**211,451**	190,720	180,516	154,825	164,042
Other	**5,812**	5,501	5,428	5,082	5,039
Total retail	**647,186**	618,860	584,313	516,301	536,827
Sales for resale – non-affiliates	**268,850**	283,413	265,863	249,986	224,275
Sales for resale – affiliates	**76,439**	50,460	44,371	26,723	46,314
Total revenues from sales of electricity	**992,475**	952,733	894,547	793,010	807,416
Other revenues	**16,762**	17,000	15,779	76,914	16,749
Total	**$ 1,009,237**	$ 969,733	$ 910,326	$ 869,924	$ 824,165
Kilowatt-Hour Sales (in thousands):					
Residential	**2,118,106**	2,179,756	2,297,110	2,255,445	2,300,017
Commercial	**2,675,945**	2,725,274	2,969,829	2,914,133	2,902,291
Industrial	**4,142,947**	3,798,477	4,235,290	4,111,199	4,161,902
Other	**36,959**	37,905	40,229	39,890	39,635
Total retail	**8,973,957**	8,741,412	9,542,458	9,320,667	9,403,845
Sales for resale – non-affiliates	**4,624,092**	4,811,250	6,027,666	5,874,724	5,380,145
Sales for resale – affiliates	**1,679,831**	896,361	1,053,471	709,065	1,586,968
Total	**15,277,880**	14,449,023	16,623,595	15,904,456	16,370,958
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.13**	9.61	8.67	8.02	8.11
Commercial	**8.05**	7.82	6.70	6.02	6.24
Industrial	**5.10**	5.02	4.26	3.77	3.94
Total retail	**7.21**	7.08	6.12	5.54	5.71
Sales for resale	**5.48**	5.85	4.38	4.20	3.88
Total sales	**6.50**	6.59	5.38	4.99	4.93
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,480**	14,111	14,357	14,161	14,453
Residential Average Annual Revenue Per Customer	**$ 1,466**	$ 1,357	$ 1,245	$ 1,136	$ 1,172
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,156**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,204**	2,178	2,173	2,458	2,311
Summer	**2,390**	2,493	2,427	2,330	2,492
Annual Load Factor (percent)	**61.3**	56.6	62.4	60.5	61.8
Plant Availability Fossil-Steam (percent)	**81.1**	82.8	91.4	92.6	91.7
Source of Energy Supply (percent):					
Coal	**63.1**	58.1	55.7	57.7	50.8
Oil and gas	**26.1**	24.4	25.5	19.9	37.7
Purchased power –					
From non-affiliates	**3.5**	5.1	6.4	3.5	3.1
From affiliates	**7.3**	12.4	12.4	18.9	8.4
Total	**100.0**	100.0	100.0	100.0	100.0

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SOUTHERN POWER COMPANY

FINANCIAL SECTION

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2006 and 2005, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2006. 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 the standards of the Public Company Accounting Oversight Board (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-312 to II-325) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

OVERVIEW

Business Activities

Southern Power Company and its wholly-owned subsidiaries (the Company) construct, acquire, own, and manage generation assets and sell electricity at market-based prices in the Super-Southeast wholesale market. The Company focused on executing its regional strategy in 2006 by signing purchased power agreements (PPAs) with investor owned utilities and electric cooperatives as well as acquiring generation with existing PPAs.

In June 2006, the Company acquired all of the outstanding membership interests of DeSoto County Generating Company, LLC (DeSoto) from a subsidiary of Progress Energy, Inc. DeSoto owns a 344 megawatt (MW) nameplate capacity dual-fueled simple cycle combustion turbine plant in Arcadia, Florida. The Company has PPAs with Florida Power & Light Company (FP&L) covering the entire output of the plant.

In September 2006, the Company acquired all of the outstanding membership interests of Rowan County Power, LLC (Rowan) from the same subsidiary of Progress Energy, Inc. Rowan was merged into the Company and the Company now owns a 986 MW nameplate capacity dual-fired generating plant near Salisbury, North Carolina. The Company currently has PPAs with Duke Power, LLC (Duke), North Carolina Municipal Power Agency No. 1 (NCMPA1), and Energy United Electric Membership Corporation (EnergyUnited) covering much of the output of the plant.

In 2006, the Company continued construction on three ongoing projects. One project is Franklin Unit 3, a combined cycle unit with an expected capacity of 621 MW near Smiths, Alabama. This plant is expected to be completed in 2008. The second project is Oleander Unit 5, a combustion turbine with an expected capacity of 160 MW, in Brevard County, Florida, which is expected to be completed in late 2007. The third project is an Integrated Gasification Combined Cycle (IGCC) project in Orlando, Florida, expected to be completed in 2010. This project is a partnership with the Orlando Utilities Commission (OUC) and is located at OUC's Stanton Energy Center site. A cooperative agreement with the U.S. Department of Energy (DOE) provides up to $235 million in funding to be applied by the joint owners for the construction and demonstration of the gasification portion of this project.

As of December 31, 2006, the Company had 6,733 MW nameplate capacity in commercial operation. The weighted average duration of the Company's wholesale contracts exceeds 10 years, which reduces re-marketing risk. The Company continues to face challenges at the federal regulatory level relative to market power and affiliate transactions. See FUTURE EARNINGS POTENTIAL – "FERC Matters" for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators consist of plant availability, peak season equivalent forced outage rate (EFOR), and net income. Plant availability shows the percentage of time during the year that the Company's generating units are available to be called upon to generate (the higher the better), whereas the EFOR more narrowly defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal. The Company's actual performance in 2006 surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2006 earnings were $124.5 million, a $9.7 million increase over 2005. This increase was primarily the result of new PPAs starting or acquired in the period, including contracts with Piedmont Municipal Power Authority (PMPA) and EnergyUnited and the PPAs related to the acquisition of Plants DeSoto and Rowan in June 2006 and September 2006, respectively. Short-term energy sales and increased sales from existing resources also contributed to this increase.

The Company's 2005 earnings were $114.8 million, a $3.3 million increase over 2004. The 2005 increase was primarily attributed to the acquisition of Oleander in June 2005 and additional revenues associated with energy margins from fully contracted units, which were partially offset by the expiration of PPAs at Plant Dahlberg. In addition, interest expense increased in connection with the Oleander acquisition as well as the reduction in interest capitalized related to the conclusion of the Company's initial construction program.

The Company's 2004 earnings were $111.5 million. This was a decrease of $43.6 million from 2003 primarily the result of a one time $50 million gain in May 2003 from the termination of PPAs with Dynegy Inc.

RESULTS OF OPERATIONS

A condensed income statement is as follows:

	Amount	Increase (Decrease) From Prior Year		
	2006	2006	2005	2004
		(in thousands)		
Operating revenues	$777,048	$ (3,956)	$ 79,693	$ 19,531
Fuel	145,236	(63,772)	81,905	11,847
Purchased power	170,697	10,641	(28,400)	3,155
Other operations and maintenance	95,276	14,471	5,610	12,954
Depreciation and amortization	65,959	11,705	3,093	12,149
Taxes other than income taxes	15,637	2,323	2,041	4,608
Total operating expenses	492,805	(24,632)	64,249	44,713
Operating income	284,243	20,676	15,444	(25,182)
Other income, net	2,191	(188)	(29)	4,002
Less –				
Interest expense and other, net	80,154	832	13,234	34,380
Income taxes	81,811	9,978	(1,102)	(12,286)
Cumulative effect of accounting change	-	-	-	(367)
Net Income	$124,469	$ 9,678	$ 3,283	$(43,641)

Revenues

Operating revenues in 2006 were $777 million, a $4.0 million (0.5 percent) decrease from 2005. This decrease was primarily due to reduced energy revenues as a result of lower natural gas prices. This reduction is accompanied by a reduction in related fuel costs and does not have a significant net income impact. Offsetting this energy related reduction were increased sales from a full year of operations at Plant Oleander and new sales under PPAs with PMPA, EnergyUnited and those PPAs acquired in the DeSoto and Rowan acquisitions. See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and Note 2 to the financial statements under "DeSoto and Rowan Acquisitions."

Operating revenues in 2005 were $781.0 million, a $79.7 million (11.4 percent) increase from 2004. This increase was primarily due to PPAs related to the Oleander acquisition, a new PPA with Flint Energies (Flint EMC), and a full year of revenue from PPAs with Georgia Power at Plant Franklin Unit 2 and Plant Harris Unit 2. The Georgia Power PPA for Plant Franklin Unit 2 had a scheduled sales increase in June 2004, while the PPA for Plant Harris Unit 2 became effective in June 2004. These increases were partially offset by the expiration of PPAs at Plant Dahlberg.

Operating revenues in 2004 were $701.3 million, a $19.5 million (2.9 percent) increase from 2003. The increase was primarily related to a full year of revenues under PPAs from new units. Plant Harris Units 1 and 2 and Plant Franklin Unit 2 were placed in service in June 2003. Plant Stanton A was placed in service in October 2003.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and represent the greatest contribution to net income. Energy under PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges. Details of these PPA capacity and energy revenues are as follows:

	2006	2005	2004
		(in thousands)	
Capacity revenues			
Affiliates	$279,089	$278,221	$247,914
Non-Affiliates	103,365	68,645	73,980
Total	382,454	346,866	321,894
Energy revenues			
Affiliates	190,046	254,844	124,837
Non-Affiliates	144,891	141,496	80,825
Total	334,937	396,340	205,662
Total PPA revenues	$717,391	$743,206	$527,556

Revenues from sales to affiliated companies within the Southern Company system that are not covered by PPAs are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC), and will vary depending on demand and the availability and cost of generating resources at each company that participates in the centralized operation and dispatch of the Southern Company fleet of generating plants (Southern Pool). These transactions do not have a significant impact on earnings since the energy is generally sold at variable cost.

Other operating revenues increased by $4.6 million (360.4 percent) from 2005. This increase reflects new PPAs in 2006 with PMPA and EnergyUnited and is primarily the result of additional transmission revenues. These transmission revenues are largely offset by additional transmission expenses included in operations and maintenance expenses and do not contribute substantially to net income.

Expenses

Fuel and Purchased Power

In 2006, fuel expense decreased by $63.8 million (30.5 percent) compared to 2005. The decrease was driven by a 25.4 percent reduction in the average cost of natural gas. Gas prices in 2006 were lower and had less weather-driven volatility than the previous two years. The fuel price decrease was partially offset by volume increases primarily from increased generation at Plants Wansley and Dahlberg.

In 2005, fuel expense increased by $81.9 million (64.4 percent). The increase was driven by a 54.2 percent increase in the average cost of natural gas per decatherm. In 2004, fuel expense increased by $11.8 million (10.3 percent), primarily due to increased gas transportation expenses associated with Plant Harris Unit 2 prior to its commitment with Georgia Power. The average cost of natural gas per decatherm also increased 8.3 percent from 2003 to 2004.

While prices for fuel have moderated somewhat in 2006, a significant upward trend in the cost of natural gas has emerged since 2003, and volatility in this market is expected to continue. Higher natural gas prices in the United States are the result of increased demand and slightly lower gas supplies despite increased drilling activity. Natural gas production and supply interruptions, such as those caused by 2004 and 2005 hurricanes, result in an immediate market response; however, the long-term impact of this price volatility may be reduced by imports of liquefied natural gas if new liquefied gas facilities are built. The Company's PPAs generally provide that the counterparties are responsible for substantially all of the cost of fuel and fuel costs do not significantly affect net income. Under most of the PPAs, either the Company incurs the fuel expense and concurrently recovers the cost through energy revenues or the counterparty purchases the fuel directly.

Purchased power increased $10.6 million (6.6 percent) in 2006, primarily due to increased purchases of lower cost energy resources from the Southern Pool and contracts with PMPA and Dalton Utilities. Purchased power volume in 2006 increased 51 percent compared to 2005. This follows a $28.4 million (15.1 percent) decrease in 2005, due to limited short term market energy sales as the Company's generating resources were employed for increased PPA commitments.

Purchased power increased $3.2 million (1.7 percent) in 2004 over 2003, consisting of a $15.4 million increase for non-affiliates and a $12.3 million decrease for affiliates as a result of the availability of lower cost energy from contracts with Georgia electric membership corporations (EMC) and North Carolina municipalities, in addition to other market sources. Purchased power may change markedly year to year as weather, fuel prices, and availability of lower cost energy resources influence the demand and optimal economics to serve the Company's contracts.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the Southern Pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

Other Operations and Maintenance

Other operations and maintenance expenses have increased during the period from 2003 through 2006. In 2006, other operations and maintenance expenses increased $14.5 million (17.9 percent). In 2005 and 2004, other operations and maintenance increased $5.6 million and $13.0 million, respectively. The year-to-year increases are primarily the result of the operation of new generating units. In 2003, Plant Franklin Unit 2, Plant Harris Units 1 and 2, and Plant Stanton A were placed in service at differing dates. Unit additions from acquisitions began in 2005 with Plant Oleander and have continued in 2006 with Plant DeSoto and Plant Rowan. See Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition."

Depreciation and Amortization

Depreciation and amortization increased by $11.7 million (21.6 percent) from 2005. This increase was primarily the result of higher depreciation rates from a new depreciation study adopted in March 2006. The change in rates contributed an additional $6.3 million of expense. Additional plant in service from acquisitions also contributed $5.4 million to the increase. Additions have included Plant Oleander in June 2005, Plant DeSoto in June 2006, and Plant Rowan in September 2006.

Depreciation and amortization increased by $3.1 million in 2005 and by $12.1 million in 2004. Prior increases have been primarily through additional plant in service.

Taxes Other than Income Taxes

Taxes other than income taxes increased $2.3 million (17.4 percent) in 2006. This was primarily due to incremental ad valorem taxes on new assets. In 2005 and 2004, taxes other than income taxes increased $2.0 million and $4.6 million, respectively. Increases in taxes other than income taxes have followed additions to plant in service since 2002. Plant in service additions have come through completed construction activities or acquisitions.

Interest

Interest expense has increased by $0.8 million, $13.2 million, and $34.4 million in 2006, 2005, and 2004, respectively. The 2006 increase was primarily the result of additional debt incurred for acquisitions. This increase was offset by higher levels of interest capitalized during construction reflecting the Company's construction program. Prior year increases were due to incremental debt incurred for the Oleander acquisition and construction. Additional factors for prior year increases included a lower percentage of interest costs being capitalized as projects reached completion, were sold, or were suspended during those periods. Plant McIntosh Units 10 and 11 were transferred to Georgia Power and Savannah Electric and construction was suspended on Plant Franklin Unit 3 during 2004, effectively ceasing all capitalized interest. For additional information, see FUTURE EARNINGS POTENTIAL – "Construction Projects — Plant Franklin Unit 3, Plant Oleander Unit 5, and IGCC" and Note 3 to the financial statements under "Plant Franklin Unit 3 Construction Project" and Note 4 to the financial statements under "IGCC."

Other Income (Expense), net

Changes in other income, net in 2006, 2005, and 2004 were primarily the result of unrealized gains and losses on derivative energy contracts. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 6 to the financial statements under "Financial Instruments."

Income Taxes

Income taxes increased by $10.0 million (13.9 percent) in 2006. Income taxes decreased $1.1 million (1.5 percent) in 2005 and $12.2 million (14.4 percent) in 2004. Fluctuations in income taxes are primarily the result of changes to pre-tax income. Other factors may include new tax provisions or additional tax jurisdictions.

Effects of Inflation

When inflation exceeds projections used in market, term, and cost evaluations performed at contract initiation, the effects of inflation can create an economic loss. In addition, the income tax laws are based on historical costs. Therefore inflation creates an economic loss as the Company is recovering its costs of investments in dollars that could 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 due to large investment in utility plant with long economic lives. Conventional accounting for historical costs does not recognize this economic loss or the partially offsetting gain that arises through financing facilities with fixed money obligations such as long-term debt.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. Several factors affect the opportunities, challenges, and risks of the Company's competitive wholesale energy business. These factors include the ability to achieve sales growth while containing costs. Another major factor is federal regulatory policy, which may impact the Company's level of participation in this market. The level of future earnings depends on numerous factors including regulatory matters such as those related to affiliate contracts, sales, creditworthiness of customers, total generating capacity available in the Southeast, and the successful remarketing of capacity as current contracts expire.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale market in the Southeastern power markets. Although there is currently an oversupply of generating capacity in the Super-Southeast, opportunities remain in certain areas.

In February 2007, the Company entered into a PPA with Progress Energy Carolinas, Inc for 150 MW annually from January 2010 through December 2019 from Plant Rowan.

In October 2006, the Company entered into a PPA with Gulf Power for 292 MW annually from June 2009 through May 2014 from Plant Dahlberg. This contract was filed with the Florida Public Service Commission (PSC) in December 2006 and is subject to Florida PSC and FERC approval.

In September 2006, the Company acquired PPAs with Duke for 456 MW annually and PPAs with NCMPA1 for an average of 130 MW annually as part of the Rowan acquisition. These PPAs expire at various times through 2030.

In May 2006, the Company entered into three PPAs with EnergyUnited. Under two full requirements PPAs, the Company will sell an average monthly capacity of 177 MW from September 2006 through December 2010 and 351 MW from January 2011 through December 2025. The Company will also sell 205 MW of annual capacity through a block contract to be served from Plant Rowan from January 2011 through December 2025. See Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" for additional information.

In June 2006, the Company acquired PPAs with FP&L as part of the DeSoto acquisition. These PPAs cover the plant's capacity and energy through May 2007. See Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" for additional information.

In April 2006, the Company entered into a PPA with Progress Ventures, Inc. for 621 MW of annual capacity from 2009 through 2015 with an option to extend through 2020. This capacity is expected to be provided from the expected 621 MW capacity of Plant Franklin Unit 3. See Note 3 to the financial statements under "Plant Franklin Unit 3 Construction Project" for additional information.

In February 2006, the Company entered into a PPA with Florida Municipal Power Agency (FMPA) for the expected 160 MW capacity from Plant Oleander Unit 5. The PPA will commence upon the completion of the plant, which is scheduled for late 2007, and will extend through 2022.

In June 2005 as part of the Oleander acquisition, the Company acquired existing PPAs with FP&L and Seminole Electric Cooperative, Inc. (Seminole). The FP&L PPA is for one unit and extends through the end of May 2007. The Seminole PPA is for three units at Plant Oleander and extends through the end of 2009. In February 2006, the Company signed an extension of the FP&L PPA for approximately 160 MW of annual capacity through May 2012. Also in February 2006, the Company signed an additional PPA with Seminole for approximately 465 MW of annual capacity through December 2015. See Note 2 to the financial statements under "Oleander Acquisition" for additional information.

In August 2004, the Company entered into two PPAs with FP&L. Under the PPAs, the Company will provide FP&L with a total of 790 MW of annual capacity from Plant Harris Unit 1 and Plant Franklin Unit 1 for the period from June 2010 through December 2015. A similar PPA with Progress Energy Florida was signed in November 2004 for 350 MW of annual capacity from Franklin Unit 1 for the period June 2010 through December 2015. The Florida PSC has approved these contracts.

Also in 2004, the Company executed multiple agreements with existing customers. For the years 2007 through 2009, the Company will sell an average of approximately 132 MW of additional wholesale capacity from existing resources to Flint EMC. The Company also agreed to a 10-year extension of the OUC PPA for Stanton Unit A through October 2023.

The Company has entered into long-term power sales agreements for a portion of its generating capacity as follows:

Project	Capacity (megawatts) [1]	Initial Term [2]
Affiliated		
Franklin Unit 1	563	6/02-5/10
Franklin Unit 2	625	6/03-5/11
Wansley Units 6 & 7	1,148	6/02-12/09
Harris Unit 1	627	6/03-5/10
Harris Unit 2	628	6/04-5/19
Dahlberg	292	6/09-5/14
Non-Affiliated		
Franklin Unit 1 (FP&L/Progress Florida)	540	6/10-12/15
Harris Unit 1 (FP&L)	600	6/10-12/15
Franklin Unit 3 (Progress Ventures)	621	1/09-12/15
Stanton A (OUC)	338	11/03-10/23
Stanton A (Kissimmee Utilities Authority, FMPA)	85	11/03-10/13
Oleander (FP&L)	155	6/05-5/12
Oleander (Seminole)	465	6/05-12/09
Oleander (Seminole)	465	1/10-12/15
Oleander (FMPA)	160	12/07-12/22
DeSoto (FP&L)	320	6/06-5/07
Rowan (Duke)	152	9/06-5/10
Rowan (Duke)	304	9/06-12/10
Rowan (NCMPA1)	50	9/06-12/15
Rowan (NCMPA1)	138	1/11-12/30
Rowan (Progress Energy Carolinas)	150	1/10-12/19
Rowan (EnergyUnited) Block	205	1/11-12/25
Flint EMC Block	132	1/05-12/09

Project	Capacity (megawatts) [1]	Initial Term [2]
GA EMC Full Requirements [3]	397	6/02-12/09
PMPA Full Requirements	165	1/06-12/10
EnergyUnited Full Requirements	177	9/06-12/10
EnergyUnited Full Requirements	351	1/11-12/25

1. Capacity value for full requirements PPAs is average monthly MW.
2. Excluding automatic renewal provisions.
3. GA EMC full requirements consist of 11 EMCs, each with an annual capacity of 62-434 MW. At the 2009 ending date, there is an option to convert from full requirements to a fixed capacity sale for the majority of the EMCs. The Sawnee EMC and Coweta-Fayette EMC conversion option is 12/12.

The Company has PPAs with some of the traditional operating companies and with other investor owned utilities and electric cooperatives. Although some of the Company's PPAs are with Southern Company's traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flow to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities.

As a general matter, existing PPAs provide that the purchasers are responsible for substantially all of the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for procuring and transporting the fuel to the particular generating facility.

Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or dollars-per-megawatt hour. In general, the Company has long-term service contracts with General Electric (GE) to reduce its exposure to certain operation and maintenance costs relating to GE equipment. See Note 7 to the financial statements under "Long-Term Service Agreements" for additional information.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's or Moody's downgrades the credit ratings of such counterparty to an unacceptable credit rating or the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.7 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $4.5 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the IIC discussed below. On January 3, 2007, the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The majority of the Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Savannah Electric, the Company, and Southern Company Services, Inc. (SCS), as agent, under the terms of which the Southern Pool is operated, and, in particular, the propriety of the continued inclusion of the Company as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining the Company as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of the Company, the FERC authorized the Company's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of the Company. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The Company's cost of the modifications is expected to be approximately $9 million per year.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns could also affect the Company.

New environmental legislation or regulations, or changes to existing statutes or regulations could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because each of the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts, can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company as a result of generating facilities that may be acquired or constructed in the future cannot be predicted at this time.

Litigation over environmental issues and claims of various types, including property damage, personal injury and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such potential litigation against the Company cannot be predicted at this time.

Construction Projects

Plant Franklin Unit 3

The Company restarted construction activities on Plant Franklin Unit 3 in 2006, with an expected completion date in late 2008. The total cost is expected to be approximately $338.8 million, of which $198.3 million had been spent as of December 31, 2006. The expected capacity of this unit is 621 MW and will be used to provide annual capacity for a PPA with Progress Ventures, Inc. from 2009 through 2015. See Note 3 to the financial statements under "Plant Franklin Unit 3 Construction Project" for more information.

Plant Oleander Unit 5

The Company is constructing an additional unit at Plant Oleander. Oleander Unit 5 is a combustion turbine with an expected capacity of 160 MW and is expected to be completed in December 2007. The unit's capacity will be used to provide annual capacity for a PPA with FMPA. The total cost of this project is expected to be approximately $59 million, of which $18.9 million had been spent as of December 31, 2006.

Integrated Gasification Combined Cycle (IGCC)

In December 2005, the Company and OUC executed definitive agreements for development of the IGCC, a project of approximately 285 MW in Orlando, Florida, adjacent to Plant Stanton Unit A, which is co-owned by the Company, OUC, and others. The definitive agreements provide that the Company will own at least 65 percent of the gasifier portion of the project. OUC will own the remainder of the gasifier portion and 100 percent of the combined cycle portion of the project. OUC will make capacity payments for all of the Company's gasifier capacity once the plant is in commercial operation. The Company will construct the project and bill OUC a fixed price for its share in the project. The Company will manage operations after construction is completed using a joint staff of OUC and SCS employees. The Company signed a cooperative agreement with the DOE in February 2006, which provides for up to $235 million in grant funding for the construction and demonstration of the gasification portion of the project. The IGCC project is subject to National Environmental Policy Act review as well as state environmental review, requires certain regulatory approvals, and is expected to begin commercial operation in 2010. The total cost related to the gasifier portion of the IGCC project is currently being reviewed, and may be higher than earlier estimates due to increases in commodity costs and increased market demand for labor. The Company had spent $7.8 million as of December 31, 2006. The Company has the option under the agreements to end its participation in the project at the end of the project definition phase which is expected to be during 2007. The final outcome of this matter cannot now be determined.

Other Matters

The Company completed a depreciation study in 2006 and updated the composite depreciation rates for its property, plant, and equipment. This change in estimate arises from changes in useful life assumptions for certain components of plant in service determined by a detailed engineering study. This change increased depreciation expense and reduced net income. The 2006 income impact of this change was $3.8 million. See Note 1 to the financial statements under "Depreciation" for additional information.

From time to time, the Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended and interpreted (SFAS No. 133). In general, the Company's power sale transactions can be classified in one of four categories: non-derivatives, normal sales, cash flow hedges, and mark to market. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" and Notes 1 and 6 to the financial statements under "Financial Instruments." The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract. Factors that must be considered in making these determinations include:

- Assessing whether a sales contract meets the definition of a lease
- Assessing whether a sales contract meets the definition of a derivative
- Assessing whether a sales contract meets the definition of a capacity contract
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery
- Ensuring that the contract quantities do not exceed available generating capacity
- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged
- Assessing hedge effectiveness at inception and throughout the contract term.

Normal Sale and Non-Derivative Transactions

The Company has capacity contracts that provide for the sale of electricity and that involve physical delivery in quantities within the Company's available generating capacity. These contracts either do not meet the definition of a derivative or are designated as normal sales thus exempting them from fair value accounting under SFAS No. 133. As a result, such transactions are accounted for as executory contracts; additionally the related revenue is recognized in accordance with Emerging Issues Task Force (EITF) No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts" on an accrual basis in amounts equal to the lesser of the levelized amount or the amount billable under the contract, over the respective contract periods. Revenues are recorded on a gross basis in accordance with EITF No. 99-19 "Reporting Revenue Gross as a Principal versus Net as an Agent." Revenues from transactions that do not meet the definition of a derivative are also recorded in this manner. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the year ended December 31, 2006.

Cash Flow Hedge Transactions

The Company designates other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions. These contracts are marked to market through other comprehensive income over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark to Market Transactions

Contracts for sales of electricity that are not normal sales and are not designated as cash flow hedges are marked to market and recorded directly through net income. Net unrealized gains on such contracts were not material for the year ended December 31, 2006.

Percentage of Completion

The Company is currently engaged in a long term contract for engineering, procurement, and construction services to build a combined cycle unit for OUC. Construction activities commenced in 2006 and are expected to be complete by the end of 2010. Revenue and costs are recognized using the percentage-of-completion method. The Company utilizes the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Revenues and costs are recognized by applying this percentage to the total revenues and estimated costs of the contract.

Asset Impairments

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company evaluates the carrying value of these assets under FASB Statement No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets," whenever indicators of potential impairment exist. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses, or a projection of continuing losses or a significant decrease in market prices. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity
- Future power and natural gas prices, which have been quite volatile in recent years
- Future operating costs.

To date, the Company's evaluations of its assets have not required any impairment to be recorded. See Note 2 to the financial statements under "Plant Franklin Unit 3 Construction Project" for additional information.

Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for these acquisitions under the purchase method in accordance with FASB Statement No. 141,"Business Combinations." Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the identifiable assets and liabilities based on a valuation prepared by a third party.

New Accounting Standards

Guidance on Considering the Materiality of Misstatements

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses how the effects of prior year uncorrected misstatements should be considered when quantifying misstatements in current year financial statements. SAB 108 requires companies to quantify misstatements using both a balance sheet and an income statement approach and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. When the effect of initial adoption is material, companies will record the effect as a cumulative effect adjustment to beginning of year retained earnings. The provisions of SAB 108 were effective for the Company for the year ended December 31, 2006. The adoption of SAB 108 did not have a material impact on the Company's financial statements.

Income Taxes

In July 2006, the FASB issued Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" (FIN 48). This interpretation requires that tax benefits must be "more likely than not" of being sustained in order to be recognized. The Company adopted FIN 48 effective January 1, 2007. The adoption of FIN 48 did not have a material impact on the Company's financial statements.

Fair Value Measurement

The FASB issued FASB Statement No. 157 "Fair Value Measurements" (SFAS No. 157) in September 2006. This standard provides guidance on how to measure fair value where it is permitted or required under other accounting pronouncements. SFAS No. 157 also requires additional disclosures about fair value measurements. The Company plans to adopt SFAS No. 157 on January 1, 2008 and is currently assessing its impact.

Fair Value Option

In February 2007, the FASB issued FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company plans to adopt SFAS No. 159 on January 1, 2008 and is currently assessing its impact.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The major changes in the Company's financial condition during 2006 have been the acquisitions of Plant DeSoto in June and Plant Rowan in September, the continued construction of Plant Franklin Unit 3, Plant Oleander Unit 5, and the IGCC, and the completion of the sale of Cherokee Falls Development of South Carolina LLC (a former subsidiary of the Company) and its assets to Southern Company's nuclear development affiliate. The acquisitions of Plant DeSoto and Plant Rowan resulted in $409.2 million of utility plant and working capital in 2006. Total expenditures on current construction projects are $225.0 million. Other changes have included the payment of $77.7 million in dividends to Southern Company and the issuance of $200 million of senior notes. The Company has received investment grade ratings from the major rating agencies with respect to its debt.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks.

The Company's current liabilities frequently exceed current assets due to the use of short-term debt as a funding source. At December 31, 2006, the Company had approximately $29.9 million of cash and cash equivalents to meet short-term cash needs and contingencies. To meet liquidity and capital resource requirements, the Company had at December 31, 2006, $400 million of unused committed credit arrangements with banks that expire in 2011. Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. At December 31, 2006, there was $123.8 million of commercial paper outstanding. See Note 6 to the financial statements under "Commercial Paper" for additional information.

Financing Activities

During 2006, the Company issued $200 million of 30-year unsecured long-term senior notes. The proceeds of the issuance were used to repay a portion of the Company's outstanding short-term indebtedness and for other general corporate purposes, including the Company's continuous construction program. In conjunction with issuing the securities, the Company terminated $200 million in interest swaps at a cost of $8.1 million. This cost will be amortized over a 10-year period.

The issuance of all securities by the Company is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2 or to BBB- or Baa3 or below. Generally, collateral may be provided with a Southern Company guaranty, letter of credit, or cash. These contracts are primarily for physical electricity purchases and sales. At December 31, 2006, the maximum potential collateral requirements at BBB and Baa2 ratings were approximately $8.6 million, at BBB- or Baa3 ratings were approximately $264.7 million, and below BBB- or Baa3 ratings were approximately $424.2 million. In addition, through the acquisition of Plant Rowan, the Company assumed a PPA with Duke that could require collateral, but not accelerated payment, in the event of a downgrade to the Company's credit rating to below BBB- or Baa3. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade, limited to the Company's remaining obligations under the contract. The Company, along with the other members of the Southern Pool, is also party to certain derivative agreements that could require collateral and/or accelerated payment in the event of a credit rating change to below investment grade for Alabama Power and/or Georgia Power. These agreements are primarily for natural gas and power price risk management activities. At December 31, 2006, the Company's total exposure to these types of agreements was approximately $27.4 million

Market Price Risk

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

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is limited. To mitigate residual risks in those areas, the Company enters into fixed-price contracts for the sale of electricity.

The fair value of changes in derivative energy contracts and year-end valuations were as follows at December 31:

	Changes in Fair Value	
	2006	2005
	(in thousands)	
Contracts beginning of year	$ 223	$ 9
Contracts realized or settled	(5,233)	(168)
New contracts at inception	-	-
Changes in valuation techniques	-	-
Current period changes (a)	6,860	382
Contracts end of year	$ 1,850	$ 223

(a) Current period changes also include the changes in fair value of new contracts entered into during the period.

At December 31, 2006, the sources of the valuation prices were as follows:

Source of 2006 Year-End Valuation Prices

	Total Fair Value	Maturity 2007	Maturity 2008-2009
		(in thousands)	
Actively quoted	$ 413	$ 413	$-
External sources	1,437	1,437	-
Models and other methods	-	-	-
Contracts end of year	$1,850	$1,850	$-

Unrealized pre-tax gains and losses on electric contracts used to hedge anticipated sales, and gas contracts used to hedge anticipated purchases and sales, are deferred in other comprehensive income. Gains and losses on contracts that do not represent hedges are recognized in the income statement as incurred.

At December 31, 2006, the fair value gains/(losses) of energy related derivative contracts were reflected in the financial statements as follows:

	Amounts
	(in thousands)
Net Income	$ 493
Accumulated other comprehensive income	1,357
Total fair value	$1,850

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented. The Company is exposed to market-price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's policy is to enter into agreements with counterparties that have investment grade credit ratings by Standard & Poor's and Moody's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

At December 31, 2006, the Company had no variable long-term debt outstanding. Therefore, there would be no effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates. The Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term.

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $240.7 million for 2007, $481.9 million for 2008, and $844.4 million for 2009. These amounts include estimates for potential plant acquisitions and/or new construction. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental regulations; FERC rules and transmission regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. Currently, there are three plants under construction.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2007	2008-2009	2010-2011	After 2011	Total
			(in millions)		
Long-term debt[a] –					
Principal	$ 1.2	$ -	$ -	$1,300.0	$1,301.2
Interest	74.4	148.6	148.6	457.1	828.7
Operating leases	0.6	0.6	0.6	10.9	12.7
Purchase commitments[b] –					
Capital[c]	240.7	1,326.3	-	-	1,567.0
Natural gas[d]	100.3	222.0	112.3	264.7	699.3
Long-term service agreements	28.2	62.4	84.7	883.0	1,058.3
Total	$445.4	$1,759.9	$346.2	$2,915.7	$5,467.2

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $95.3 million, $80.8 million, and $75.2 million, respectively.

(c) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures.

(d) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on New York Mercantile Exchange future prices at December 31, 2006.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2006 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning environmental regulations and expenditures, financing activities, access to sources of capital, impacts of the adoption of new accounting rules, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by 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, implementation of the Energy Policy Act of 2005, and also changes in environmental, tax 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, regulatory investigations, proceedings or inquiries, including FERC matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and population, and business growth (and declines);
- available sources and costs of fuels;
- advances in technology;
- state and federal rate regulations;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, including the IGCC;
- 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 ability of counterparties of the Company to make payments as and when due;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, pandemic health events such as an avian influenza, or similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Southern Power Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Revenues:			
Sales for resale --			
Non-affiliates	**$279,384**	$223,058	$266,463
Affiliates	**491,762**	556,664	425,065
Other revenues	**5,902**	1,282	9,783
Total operating revenues	**777,048**	781,004	701,311
Operating Expenses:			
Fuel	**145,236**	209,008	127,103
Purchased power --			
Non-affiliates	**53,795**	57,182	76,652
Affiliates	**116,902**	102,874	111,804
Other operations	**73,804**	61,235	58,111
Maintenance	**21,472**	19,570	17,084
Depreciation and amortization	**65,959**	54,254	51,161
Taxes other than income taxes	**15,637**	13,314	11,273
Total operating expenses	**492,805**	517,437	453,188
Operating Income	**284,243**	263,567	248,123
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(80,154)**	(79,322)	(66,088)
Other income (expense), net	**2,191**	2,379	2,408
Total other income and (expense)	**(77,963)**	(76,943)	(63,680)
Earnings Before Income Taxes	**206,280**	186,624	184,443
Income taxes	**81,811**	71,833	72,935
Net Income	**$124,469**	**$114,791**	**$111,508**

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005, and 2004
Southern Power Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Operating Activities:			
Net income	**$ 124,469**	$ 114,791	$ 111,508
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**82,365**	68,210	65,838
Deferred income taxes and investment tax credits, net	**33,150**	24,055	23,510
Deferred revenues	**2,248**	(370)	10,064
Tax benefit of stock options	**-**	686	415
Accumulated deferred billings on construction contract	**12,810**	-	-
Accumulated deferred costs on construction contract	**(7,198)**	-	-
Other, net	**2,156**	2,777	9,957
Changes in certain current assets and liabilities --			
Receivables	**38,479**	(42,355)	(14,009)
Fossil fuel stock	**(374)**	(4,316)	2,894
Materials and supplies	**(119)**	(4,096)	(1,715)
Other current assets	**(3,003)**	(5,900)	4,144
Accounts payable	**(34,163)**	41,662	(13,844)
Accrued taxes	**(8,522)**	5,782	32,330
Accrued interest	**687**	535	(1,386)
Other current liabilities	**-**	-	(306)
Net cash provided from operating activities	**242,985**	201,461	229,400
Investing Activities:			
Property additions	**(91,491)**	(30,780)	(115,606)
Acquisition of plant facilities	**(409,213)**	(210,323)	-
Sale of property to affiliates	**15,674**	-	414,582
Change in construction payables, net	**10,965**	(124)	(14,349)
Other	**-**	-	(10,043)
Net cash provided from (used for) investing activities	**(474,065)**	(241,227)	274,584
Financing Activities:			
Increase (decrease) in notes payable, net	**13,060**	110,692	(114,349)
Proceeds --			
Senior notes	**200,000**	-	-
Capital contributions from parent company	**108,689**	5,022	2,808
Redemptions --			
Senior notes	**-**	-	(50,000)
Other long-term debt	**(200)**	(200)	-
Capital distributions to parent company	**-**	-	(113,000)
Payment of common stock dividends	**(77,700)**	(72,400)	(207,000)
Other	**(10,471)**	(958)	-
Net cash provided from (used for) financing activities	**233,378**	42,156	(481,541)
Net Change in Cash and Cash Equivalents	**2,298**	2,390	22,443
Cash and Cash Equivalents at Beginning of Year	**27,631**	25,241	2,798
Cash and Cash Equivalents at End of Year	**$ 29,929**	$ 27,631	$ 25,241
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $5,648, $- and $17,368 capitalized, respectively)	**$ 65,206**	$ 64,487	$ 52,146
Income taxes (net of refunds)	**53,608**	33,751	13,313

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2006 and 2005
Southern Power Company and Subsidiary Companies 2006 Annual Report

Assets	2006	2005
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 29,929	$ 27,631
Receivables --		
Customer accounts receivable	16,789	20,953
Other accounts receivable	125	93
Affiliated companies	26,215	60,505
Fossil fuel stock, at average cost	11,056	7,221
Materials and supplies, at average cost	19,877	15,628
Prepaid service agreements -- current	30,280	6,178
Other prepaid expenses	5,878	4,610
Other	2,006	251
Total current assets	142,155	143,070
Property, Plant, and Equipment:		
In service	2,434,146	2,030,996
Less accumulated provision for depreciation	219,654	161,358
	2,214,492	1,869,638
Construction work in progress	260,279	218,812
Total property, plant, and equipment	2,474,771	2,088,450
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	51,615	46,447
Other --		
Affiliated	4,473	4,496
Other	17,929	20,513
Total deferred charges and other assets	74,017	71,456
Total Assets	$2,690,943	$2,302,976

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2006 and 2005
Southern Power Company and Subsidiary Companies 2006 Annual Report

Liabilities and Stockholder's Equity	2006	2005
	(in thousands)	
Current Liabilities:		
Securities due within one year	$ 1,209	$ 200
Notes payable	123,752	110,692
Accounts payable --		
Affiliated	33,205	65,262
Other	16,453	7,651
Accrued taxes --		
Income taxes	393	3,477
Other	2,183	2,524
Accrued interest	29,849	29,161
Other	4,840	71
Total current liabilities	211,884	219,038
Long-Term Debt:		
Senior notes --		
6.25% due 2012	575,000	575,000
4.875% due 2015	525,000	525,000
6.375% due 2036	200,000	-
Other long-term debt	-	1,285
Unamortized debt discount	(3,155)	(1,765)
Long-term debt	1,296,845	1,099,520
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	106,016	68,535
Deferred capacity revenues — affiliated	36,313	37,534
Other --		
Affiliated	8,958	10,792
Other	5,423	1,214
Total deferred credits and other liabilities	156,710	118,075
Total Liabilities	1,665,439	1,436,633
Common Stockholder's Equity:		
Common stock, par value $0.01 per share --		
Authorized -- 1,000,000 shares		
Outstanding -- 1,000 shares	-	-
Paid-in capital	854,933	746,243
Retained earnings	211,295	164,525
Accumulated other comprehensive income (loss)	(40,724)	(44,425)
Total common stockholder's equity	1,025,504	866,343
Total Liabilities and Stockholder's Equity	$2,690,943	$2,302,976
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2006, 2005, and 2004
Southern Power Company and Subsidiary Companies 2006 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Other Comprehensive Income (loss)	Total
			(in thousands)		
Balance at December 31, 2003	$ -	$ 850,312	$ 217,626	$(56,462)	$1,011,476
Net income	-	-	111,508	-	111,508
Capital distributions to parent company	-	(113,000)	-	-	(113,000)
Capital contributions from parent company	-	3,223	-	-	3,223
Other comprehensive income (loss)	-	-	-	5,404	5,404
Cash dividends on common stock	-	-	(207,000)	-	(207,000)
Balance at December 31, 2004	-	740,535	122,134	(51,058)	811,611
Net income	-	-	114,791	-	114,791
Capital contributions from parent company	-	5,708	-	-	5,708
Other comprehensive income (loss)	-	-	-	6,633	6,633
Cash dividends on common stock	-	-	(72,400)	-	(72,400)
Balance at December 31, 2005	-	**746,243**	**164,525**	**(44,425)**	**866,343**
Net income	-	-	**124,469**	-	**124,469**
Capital contributions from parent company	-	**108,689**	-	-	**108,689**
Other comprehensive income (loss)	-	-	-	**3,701**	**3,701**
Cash dividends on common stock	-	-	**(77,700)**	-	**(77,700)**
Other	-	**1**	**1**	-	**2**
Balance at December 31, 2006	**$ -**	**$ 854,933**	**$ 211,295**	**$(40,724)**	**$1,025,504**

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2006, 2005, and 2004
Southern Power Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004
		(in thousands)	
Net income	**$124,469**	$114,791	$111,508
Other comprehensive income (loss):			
Changes in fair value of qualifying hedges, net of tax of $(2,801), $106, and $(520), respectively	**(4,263)**	164	(920)
Less: Reclassification adjustment for amounts included in net income, net of tax of $3,992, $4,155 and $3,964, respectively	**7,964**	6,469	6,324
Total other comprehensive income (loss)	**3,701**	6,633	5,404
Comprehensive Income	**$128,170**	$121,424	$116,912

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional operating companies, Southern Company Services (SCS), Southern Communications Services (SouthernLINC Wireless), Southern Company Holdings (Southern Holdings), Southern Nuclear Operating Company (Southern Nuclear), Southern Telecom and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power Company (APC), Georgia Power Company (GPC), Gulf Power Company, and Mississippi Power Company, are vertically integrated utilities providing electric service in four Southeastern states. The Company constructs, acquires, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications services to the traditional operating companies and also markets these services to the public within the Southeast. Southern Telecom provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in synthetic fuels and leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants. On January 4, 2006, Southern Company completed the sale of substantially all of the assets of Southern Company Gas, its competitive retail natural gas marketing subsidiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows accounting principles generally accepted in the United States. 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.

The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company-Florida LLC (SCF), Oleander Power Project, LP (Oleander), DeSoto County Generating Company, LLC (DCGC), and Southern Power Company – Orlando Gasification LLC (SPC-OG), which were own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A, Plant Oleander, Plant DeSoto, and the integrated gasification combined cycle (IGCC) plant, respectively. See Note 2 under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition" and Note 4 under "IGCC" for further information. All intercompany accounts and transactions have been eliminated in consolidation.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures and other services with respect to business and operations and power pool transactions. SCS also enters into fuel purchase and transportation arrangements and contracts, financial instruments for purposes of hedging and wholesale energy purchase and sale transactions for the benefit of the Company. Because the Company has no employees, all employee related charges are rendered at cost under agreements with SCS or the traditional operating companies. Costs for these services from SCS amounted to approximately $77.8 million in 2006, $51.9 million in 2005, and $46.7 million in 2004. Approximately $59.7 million in 2006, $47.8 million in 2005, and $40.3 million in 2004 were general, administrative, operations and maintenance expenses; the remainder was capitalized to construction work in progress and other deferred assets. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with GPC and APC to provide operations and maintenance services for Plants Dahlberg, Wansley, Franklin, and Harris. GPC has also supplied various services for other plants. These services are billed at cost on a monthly basis and are recorded as operations and maintenance expense in the accompanying statements of income. For the periods ended December 31, 2006, 2005, and 2004, these services totaled approximately $7.6 million, $7.1 million, and $6.6 million, respectively.

Total billings for all purchased power agreements (PPAs) in effect with affiliates totaled $467.9 million, $531.5 million, and $383.0 million in 2006, 2005, and 2004, respectively. Included in these billings were $36.3 million, $37.5 million, and $39.1 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2006, December 31, 2005, and December 31, 2004, respectively.

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

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

In 2006, the Company sold its membership interests in Cherokee Falls Development of South Carolina LLC at cost to Southern Company's nuclear development affiliate. The sales price was $15.7 million and is recorded in "Sale of property to affiliates" on the statements of cash flows.

Revenues

Capacity is sold at rates specified under contractual terms and is recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. Energy is generally sold at market-based rates and the associated revenue is recognized as the energy is delivered. Transmission revenues and other fees are recognized as incurred as other operating revenue. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" herein for additional information.

Significant portions of the Company's revenues have been derived from certain customers. For the year ended December 31, 2006, GPC accounted for 52.7 percent of revenues, APC accounted for 8.2 percent of revenues and Flint Electric Membership Corporation accounted for 4.6 percent of revenues. For the year ended December 31, 2005, GPC accounted for 53.6 percent of revenues, with APC and Savannah Electric accounting for 8.2 percent and 6.5 percent of revenues, respectively. For the year ended December 31, 2004, GPC accounted for approximately 40.3 percent of revenues, with APC and Savannah Electric accounting for 8.4 percent and 4.5 percent, respectively. Savannah Electric was merged into GPC effective July 1, 2006.

The Company has a long-term contract for engineering, procurement, and construction services to build a combined cycle unit for the Orlando Utilities Commission (OUC). Construction activities commenced in 2006 and are expected to be complete by the end of 2010. Revenue and costs are recognized using the percentage-of-completion method. The Company utilizes the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Revenues and costs are recognized by applying this percentage to the total revenues and estimated costs of the contract.

Fuel Costs

Fuel costs are expensed as the fuel is consumed.

Income and Other 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 life of the related property.

Property, Plant, and Equipment

The Company's property, plant, and equipment consist entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes materials, direct labor incurred by affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, all of which have an estimated useful life of 35 years, except combustion turbines at Plant Dahlberg, Plant Oleander, Plant Rowan, and Plant DeSoto, all of which have an estimated useful life of 40 years. These lives reflect a composite of the significant components (retirement units) that make up the plants. Depreciation studies are conducted periodically to update the composite rates.

A new depreciation study was completed and the applicable remaining plant lives and associated depreciation rates were revised in March 2006. This change in estimate was due to revised useful life assumptions for certain components of plant in service. Depreciation rates by generating facility increased from a range of 2.5 to 2.9 percent to an adjusted range of 2.8 to

3.8 percent. These changes increase depreciation expense and reduce net income. The result of these changes decreased 2006 net income by $3.8 million.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Asset Retirement Obligations and Other Costs of Removal

The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life.

At December 31, 2006, the Company had no liability for asset retirement obligations.

Interest Capitalized

Interest related to the construction of new facilities is capitalized in accordance with standard interest capitalization requirements per Financial Accounting Standards Board Statement No. 34, "Capitalization of Interest Cost."

Impairment of Long-Lived Assets and Intangibles

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

Deferred Project Development Costs

The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a power plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a new project. These costs are generally transferred to construction work in progress upon commencement of construction. The total deferred project development costs were $1.3 million at December 31, 2006, $3.8 million at December 31, 2005, and $3.2 million at December 31, 2004.

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 generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials and supplies are recorded at average cost.

Fuel Inventory

Fuel inventory includes the cost of oil and emission allowances. The Company maintains minimal oil levels for use at Plant Dahlberg, Plant Oleander, Plant DeSoto, and Plant Rowan. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income.

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

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

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2006	**$1,298**	**$1,288**
2005	1,100	1,117

The fair values were based on either closing market prices or closing prices of comparable instruments.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income and changes in the fair value of qualifying cash flow hedges, less income taxes and reclassifications of amounts included in net income.

2. ACQUISITIONS

Oleander Acquisition

In June 2005, the Company acquired all of the outstanding general and limited partnership interests of Oleander from subsidiaries of Constellation Energy Group, Inc. The results of Oleander's operations have been included in the financial statements since that date. The Company's acquisition of the general and limited partnership interests in Oleander was pursuant to a Purchase and Sale Agreement dated April 8, 2005, for an aggregate total cost of approximately $218.1 million, including approximately $11.9 million of working capital and other adjustments. Plant Oleander is a dual-fueled generating plant in Brevard County, Florida with a nameplate capacity of 628 megawatts (MW). The entire output of Plant Oleander is sold under separate PPAs with Florida Power & Light Company (FP&L) and Seminole Electric Cooperative, Inc. (Seminole). The PPA with FP&L is for one unit and extends through the end of May 2007. The Seminole PPA is for three units at Oleander and extends through the end of 2009. In February 2006, FP&L extended its PPA for approximately 160 MW through 2012 and Seminole signed an additional PPA for approximately 465 MW of capacity through 2015. The Oleander acquisition was in accordance with the Company's overall regional growth strategy.

Subsequent to the acquisition, the Company has started construction on an additional unit at the Oleander site. This will be Plant Oleander Unit 5 with an expected capacity of 160 MW. This unit will be used to supply a new Florida Municipal Power Agency (FMPA) contract starting in 2007 through the end of 2022.

Desoto and Rowan Acquisitions

Effective June 1, 2006, the Company acquired all of the outstanding membership interests of DeSoto County Generating Company, LLC (DeSoto) from a subsidiary of Progress Energy, Inc. The results of DeSoto's operations have been included in the Company's consolidated financial statements since that date. The Company's acquisition of the membership interest in DeSoto was pursuant to an agreement dated May 8, 2006, for an aggregate total cost of $79.7 million. DeSoto owns a dual-fired generating plant near Arcadia, Florida with a nameplate capacity of 344 MW. The plant's capacity and associated energy is sold under PPAs with FP&L that expire in 2007. The DeSoto acquisition was in accordance with the Company's overall regional growth strategy.

Effective September 1, 2006, the Company acquired all of the outstanding membership interests of Rowan County Power, LLC (Rowan) from a subsidiary of Progress Energy, Inc. Rowan was merged into the Company, and the results of Rowan's operations have been included in the Company's consolidated financial statements since that date. The Company's acquisition of the membership interests in Rowan was pursuant to an agreement dated May 8, 2006 for an aggregate total cost of $329.5 million. Through the Rowan acquisition, the Company owns a dual-fired generating plant near Salisbury, North Carolina with a nameplate capacity of 986 MW. Portions of Plant Rowan capacity and associated energy are sold under PPAs with Duke Power, LLC, North Carolina Municipal Power Agency No. 1, and Energy United Electric Membership Corporation (EnergyUnited). Substantially all of Plant Rowan's capacity is under contract from 2011 through 2025. The Rowan acquisition was in accordance with the Company's overall regional growth strategy.

The pro forma data of the Company below is unaudited and gives effect to the DeSoto and Rowan plant acquisitions as if they had occurred at January 1, 2005. The unaudited pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisitions been completed as of the dates presented nor should be taken as representative of any future consolidated results of operations or financial condition of the Company.

	For the Twelve Months Ended December 31	
	2006	2005
	(in thousands)	
Pro forma revenues	$795,701	$825,655
Pro forma net income	118,703	116,108

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury and citizen enforcement of environmental requirements such as opacity and other air quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in that proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period beginning February 27, 2005 could be subject to refund to the level of the default cost-based rates, pending the outcome of the proceeding. Such sales through May 27, 2006, the end of the refund period, were approximately $0.7 million for the Company. In the event that the FERC's default mitigation measures for entities that are found to have market power are ultimately applied, the Company may be required to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates. The final outcome of this matter will depend on the form in which the final methodology for assessing generation market power and mitigation rules may be ultimately adopted and cannot be determined at this time.

In addition, in May 2005, the FERC started an investigation to determine whether Southern Company satisfies the other three parts of the FERC's market-based rate analysis: transmission market power, barriers to entry, and affiliate abuse or reciprocal dealing. The FERC established a new 15-month refund period related to this expanded investigation. Any new market-based rate sales involving transactions involving any Southern Company subsidiary, including the Company, could be subject to refund to the extent the FERC orders lower rates as a result of this new investigation. Such sales through October 19, 2006, the end of the refund period, were approximately $4.5 million for the Company, of which $0.6 million relates to sales inside the retail service territory discussed above. The FERC also directed that this expanded proceeding be held in abeyance pending the outcome of the proceeding on the Intercompany Interchange Contract (IIC) discussed below. On January 3, 2007 the FERC issued an order noting settlement of the IIC proceeding and seeking comment identifying any remaining issues and the proper procedure for addressing any such issues.

The Company believes that there is no meritorious basis for these proceedings and is vigorously defending itself in this matter. However, the final outcome of this matter, including any remedies to be applied in the event of an adverse ruling in these proceedings, cannot now be determined.

Intercompany Interchange Contract

The majority of the Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among APC, GPC, Gulf Power, Mississippi Power, Savannah Electric, the Company and SCS, as agent, under the terms of which the power pool of Southern Company is operated, and, in particular, the propriety of the continued inclusion of the Company as a party to the IIC, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining the Company as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of the Company, the FERC authorized the Company's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

On October 5, 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms. On October 20, 2006, Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of the Company. Southern Company filed with the FERC on November 6, 2006 an implementation plan to comply with the modifications set forth in the order. The Company's cost of the modifications is expected to be approximately $9 million per year.

Plant Franklin Unit 3 Construction Project

In May 2003, the Company entered into an agreement with Dynegy Inc. to resolve all outstanding matters related to capacity sales contracts with subsidiaries of Dynegy, Inc. As a result of the contract termination, the Company completed limited construction activities on Plant Franklin Unit 3 to preserve the long-term viability of the project. On May 6, 2006, the Company signed a PPA with Progress Ventures, Inc. for 621 MW of capacity from Plant Franklin. To supply the annual capacity for this contract, the Company restarted construction of Plant Franklin Unit 3. The completion of this project is expected to be in late 2008 at an approximate cost of $338.8 million. As of December 31, 2006, the Company's investment in Plant Franklin Unit 3 was $198.3 million.

4. JOINT OWNERSHIP AGREEMENTS

Plant Stanton A

The Company is a 65 percent owner of Plant Stanton A, a combined-cycle project with 630 MW. The unit is co-owned by the OUC (28 percent), FMPA (3.5 percent), and Kissimmee Utility Authority (3.5 percent). The Company has a service agreement with SCS whereby SCS is responsible for the operations and maintenance of Plant Stanton A. As of December 31, 2006, $154.7 million was recorded in plant in service with associated accumulated depreciation of $13.1 million. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

IGCC

The Company is a 65 percent owner of the gasifier island portion of the ongoing IGCC project at OUC's Stanton Energy Center site. OUC will own the remaining 35 percent of the gasifier and 100 percent of the combined cycle portion of the IGCC project. The Company is constructing the project for OUC at a fixed price. OUC will purchase the Company's 65 percent capacity in the gasification island for 20 years after the date of commercial operation. In addition, the Company will manage the operations of the project after construction is completed using a joint staff of OUC and SCS employees.

A cooperative agreement with the U.S. Department of Energy (DOE) was signed in February 2006, which provides for up to $235 million in funding from the DOE to be applied by the joint owners for the construction and demonstration of the gasification portion of the project. The DOE will provide the funding in four phases throughout the development and demonstration of the gasifier. The total cost of the gasifier portion of the IGCC project is currently being reviewed and may be higher than earlier estimates due to increases in commodity costs and increased market demand for labor. The Company had spent $7.8 million as of December 31, 2006. The IGCC project, subject to National Environmental Policy Act review and state environmental reviews and certain regulatory approvals, is expected to begin commercial operation in 2010. The Company has the option to end its participation in the project at the end of the project definition phase which is expected to be during 2007. The final outcome of this matter cannot now be determined.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined tax returns for the State of Georgia, the State of Alabama, and the State of Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis, and no subsidiary is allocated more expense than would be paid if they filed a separate income tax return. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

Details of the income tax provisions are as follows:

	2006	2005	2004
	(in thousands)		
Total provision for income taxes:			
Federal:			
Current	**$39,653**	$40,468	$40,492
Deferred	**26,915**	20,437	19,939
	66,568	60,905	60,431
State:			
Current	**9,008**	7,310	8,933
Deferred	**6,235**	3,618	3,571
	15,243	10,928	12,504
Total	**$81,811**	$71,833	$72,935

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:

	2006	2005
	(in thousands)	
Deferred tax liabilities:		
Accelerated depreciation	**$(164,172)**	$(127,913)
Book/tax basis difference on asset transfer	**(4,469)**	(4,861)
Total	**(168,641)**	(132,774)
Deferred tax assets:		
Book/tax basis differences on asset transfers	**8,958**	11,878
Other comprehensive loss on interest rate swaps	**29,798**	31,727
Levelized capacity revenues	**15,404**	14,221
Other	**8,465**	6,413
Total	**62,625**	64,239
Accumulated deferred income taxes in the balance sheets	**$(106,016)**	$ (68,535)

Deferred tax liabilities are primarily the result of property related timing differences and derivative hedging instruments. The transfer of the Plant McIntosh construction project to GPC and Savannah Electric in 2004 resulted in a deferred gain for federal income tax purposes. Savannah Electric was merged in GPC as of July 1, 2006. GPC is reimbursing the Company for the related tax liability balance of $5.0 million. Of this total, $0.5 million is included in the balance sheets in "Receivables – Affiliated companies" and the remainder is included in "Deferred Charges and Other Assets: Other – Affiliated."

Deferred tax assets consist primarily of timing differences related to the recognition of capacity revenues, and the tax impact related to the deferred loss on interest rate swaps reflected in other comprehensive income. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $9.9 million. Of this total, $1.3 million is included in the balance sheets in "Accounts payable – Affiliated" and the remainder is included in "Deferred Credits and Other Liabilities: Other – Affiliated."

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

	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**4.8**	3.8	4.4
Other	**(0.1)**	(0.3)	0.1
Effective income tax rate	**39.7%**	38.5%	39.5%

6. FINANCING

Senior Notes

The Company issued a total of $200 million unsecured 30-year senior notes in 2006. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes, including the Company's construction program.

At December 31, 2006 and 2005, the Company had $1.3 billion and $1.1 billion, respectively, of senior notes outstanding.

Bank Credit Arrangements

The Company has a $400 million unsecured syndicated revolving credit facility (Facility) expiring in July 2011. The purpose of the Facility is to provide liquidity support to the Company's commercial paper program and other general corporate purposes. At December 31, 2006, the entire $400 million was available.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than ⅛ of 1 percent. For the period ended December 31, 2006, the Company incurred approximately $0.5 million in expense from commitment fees under the Facility. Under a previous credit facility, for the periods ended December 31, 2005 and 2004, the Company incurred expenses of $0.8 million and $2.1 million, respectively, from commitment fees.

The Facility contains a covenant that requires a maximum 65 percent debt to capitalization ratio, as defined in the Facility. The Facility also contains a cross default provision that would be triggered if the Company defaulted on other indebtedness above a specified threshold. As of December 31, 2006, the Company was in compliance with all such covenants.

Dividend Restriction

The Facility also contains certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs (as defined in the agreement) are at least 80 percent of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60 percent. At December 31, 2006, the Company was in compliance with these ratios and had no restrictions on its ability to pay dividends.

Commercial Paper

The Company has the ability to borrow under a commercial paper program. For the period ended December 31, 2006, the peak commercial paper balance outstanding was $380.3 million. The average amount outstanding was $166.3 million in 2006. The average annual interest rate was 5.3 percent in 2006. As of December 31, 2006, the commercial paper program had an outstanding balance of $123.8 million. The outstanding balance on December 31, 2005 was $110.7 million.

Financial Instruments

The Company enters into energy related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser.

At December 31, 2006, the fair value gains/(losses) of derivative energy contracts was reflected in the financial statements as follows:

	Amounts
	(in thousands)
Net Income	$ 493
Accumulated other comprehensive income	1,357
Total fair value	$1,850

Fair value gains or losses for cash flow hedges are recorded in other comprehensive income and reclassified to fuel expense. There were no material amounts reclassified during any year presented. For the year 2007, the reclassifications from other comprehensive income to fuel expense are also expected to be immaterial. There was no significant ineffectiveness recorded in earnings for any period presented. The Company has energy-related hedges in place through 2007. At December 31, 2006, there were approximately $9.9 million of deferred pre-tax realized net hedging gains relating to capitalized costs and revenues during the construction of specific plants. This will be reclassified from other comprehensive income to depreciation and amortization over the remaining life of the respective plants, which is approximately 31 years. For any year presented, the pre-tax gains reclassified from other comprehensive income to depreciation and amortization have been immaterial.

The Company may enter into derivatives to limit exposure to interest rate changes. The derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings. In 2006, the Company terminated interest rate derivatives at a cost of $8.1 million at the same time as the related debt was issued. The hedge cost will be amortized over 10 years.

At December 31, 2006, the Company had no interest derivatives outstanding. The Company has deferred losses totaling $78.5 million in other comprehensive income that will be amortized to interest expense through 2016. For the years 2006, 2005, and 2004, approximately $12.0 million, $11.2 million, and $10.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. During 2007, approximately $13.4 million of pre-tax losses are expected to be reclassified from other comprehensive income to interest expense.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be $240.7 million, $481.9 million, and $844.4 million in 2007, 2008, and 2009, respectively. There are currently three plants actively under construction. See Note 2 under "Oleander Acquisition," Note 3 under "Plant Franklin Unit 3 Construction Project," and Note 4 under "IGCC" for additional information.

Long-Term Service Agreements

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

In general, except for Plants Dahlberg and Oleander, these LTSAs are in effect through two major inspection cycles per unit. The Dahlberg and Oleander agreements are in effect through the first hot gas path inspections and last combustion inspections, respectively, of each unit. Scheduled payments to GE are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements are currently estimated at $1.1 billion over the remaining term of the agreements, which may range up to 30 years per unit. However, the LTSAs contain various cancellation provisions at the Company's option.

Payments made to GE prior to the performance of any planned inspections are recorded as a long-term prepayment in deferred charges and other assets on the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Fuel Commitments

SCS, as agent for the traditional operating companies and the Company, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities. In most cases, these contracts contain provisions for firm transportation costs, storage costs, minimum purchase levels, and other financial commitments.

Natural gas purchase commitments contain given volumes with prices based on various indices at the actual time of delivery. Amounts included in the chart below represent estimates based on the New York Mercantile Exchange future prices at December 31, 2006.

Year	Fuel Purchases
	(in millions)
2007	$100.3
2008	156.9
2009	65.1
2010	74.2
2011	38.1
2012 and beyond	264.7
Total	$699.3

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

Acting as an agent for all of Southern Company's traditional operating companies and the Company, SCS may enter into various types of wholesale energy and natural gas contracts. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. The creditworthiness of the Company is currently inferior to the creditworthiness of the traditional operating companies; therefore, Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize nor be responsible for any costs, losses, liabilities or damages resulting from the inclusion of the Company as a contracting party under these agreements.

8. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2006 and 2005 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
March 2006	**$139,829**	**$50,432**	**$19,900**
June 2006	**193,639**	**72,373**	**31,821**
September 2006	**270,031**	**99,303**	**45,871**
December 2006	**173,549**	**62,135**	**26,877**
March 2005	$152,821	$56,745	$23,073
June 2005	149,226	60,611	25,234
September 2005	265,611	84,555	39,227
December 2005	213,346	61,656	27,257

The Company's business is influenced by seasonal weather conditions. The Company had approximately 5,403 MW nameplate capacity and 6,733 MW nameplate capacity of generating capacity in service through May and December 2006, respectively.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2002-2006

Southern Power Company and Subsidiary Companies 2006 Annual Report

	2006	2005	2004	2003	2002
Operating Revenues (in thousands):					
Sales for resale – non-affiliates	**$ 279,384**	$ 223,058	$ 266,463	$ 278,559	$ 114,919
Sales for resale – affiliates	**491,762**	556,664	425,065	312,586	183,111
Total revenues from sales of electricity	**771,146**	779,722	691,528	591,145	298,030
Other revenues	**5,902**	1,282	9,783	90,635	738
Total	**$ 777,048**	$ 781,004	$ 701,311	$ 681,780	$ 298,768
Net Income (in thousands)	**$ 124,469**	$ 114,791	$ 111,508	$ 155,149	$ 54,270
Cash Dividends on Common Stock (in thousands)	**$ 77,700**	$ 72,400	$ 207,000	$ -	$ -
Return on Average Common Equity (percent)	**13.16**	13.68	12.23	17.65	8.94
Total Assets (in thousands)	**$ 2,690,943**	$ 2,302,976	$ 2,067,013	$ 2,409,285	$2,085,976
Gross Property Additions/Plant Acquisitions (in thousands)	**$ 500,704**	$ 241,103	$ 115,606	$ 344,362	$1,214,677
Capitalization (in thousands):					
Common stock equity	**$ 1,025,504**	$ 866,343	$ 811,611	$ 1,011,476	$ 746,604
Long-term debt	**1,296,845**	1,099,520	1,099,435	1,149,112	955,879
Total (excluding amounts due within one year)	**$ 2,322,349**	$ 1,965,863	$ 1,911,046	$ 2,160,588	$1,702,483
Capitalization Ratios (percent):					
Common stock equity	**44.2**	44.1	42.5	46.8	43.9
Long-term debt	**55.8**	55.9	57.5	53.2	56.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Unsecured Long-Term Debt –					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**BBB+**	BBB+	BBB+	BBB+	BBB+
Kilowatt-Hour Sales (in thousands):					
Sales for resale – non-affiliates	**5,093,527**	3,932,638	5,369,261	6,057,053	1,240,290
Sales for resale – affiliates	**8,493,441**	6,355,249	6,583,017	5,430,973	3,607,107
Total	**13,586,968**	10,287,887	11,952,278	11,488,026	4,847,397
Average Revenue Per Kilowatt-Hour (cents)	**5.68**	7.58	5.79	5.15	6.15
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**6,733**	5,403	4,775	4,775	2,408
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,780**	2,037	2,098	2,077	949
Summer	**2,869**	2,420	2,740	2,439	1,426
Annual Load Factor (percent)	**53.6**	48.9	54.4	54.9	51.1
Plant Availability (percent)	**98.3**	97.6	97.9	96.8	95.1
Source of Energy Supply (percent):					
Gas	**68.3**	72.6	61.9	53.4	77.4
Purchased power –					
From non-affiliates	**9.6**	9.6	24.7	30.5	5.9
From affiliates	**22.1**	17.8	13.4	16.1	16.7
Total	**100.0**	100.0	100.0	100.0	100.0

PART III

Items 10, 11, 12 (except for "Equity Compensation Plan Information" which is included herein on page III-3), 13 and 14 for Southern Company are incorporated by reference to Southern Company's definitive Proxy Statement relating to the 2007 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation" and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13 and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13 and 14 for Alabama Power, Georgia Power and Mississippi Power are incorporated by reference to the Information Statements of Alabama Power, Georgia Power and Mississippi Power relating to each of their respective 2007 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors", "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation Information," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation" and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13 and "Principal Public Accounting Firm Fees" for Item 14.

Items 11, 12 and 13 for Gulf Power will be included in an amendment to the Form 10-K for the year ended December 31, 2006 to be filed no later than April 30, 2007.

Items 10, 11, 12 and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF GULF POWER

Identification of directors of Gulf Power.

Susan N. Story
President and Chief Executive Officer
Age 46
Served as Director since 2003

C. LeDon Anchors (1)
Age 66
Served as Director since 2001

William C. Cramer, Jr. (1)
Age 54
Served as Director since 2002

Fred C. Donovan, Sr. (1)
Age 66
Served as Director since 1991

William A. Pullum (1)
Age 59
Served as Director since 2001

Winston E. Scott (1)
Age 56
Served as Director since 2003

(1) *No position other than director.*

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 27, 2006) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power.

Susan N. Story
President and Chief Executive Officer
Age 46
Served as Executive Officer since 2003

Francis M. Fisher, Jr.
Vice President – Customer Operations
Age 58
Served as Executive Officer since 1989

P. Bernard Jacob
Vice President – External Affairs and Corporate Services
Age 52
Served as Executive Officer since 2003

Ronnie R. Labrato
Vice President and Chief Financial Officer
Age 53
Served as Executive Officer since 2000

Penny M. Manuel
Vice President – Senior Production Officer
Age 44
Served as Executive Officer since 2005

Each of the above is currently an executive officer of Gulf Power, serving a term running from the last annual organizational meeting of the directors (July 27, 2006) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees.

None.

Family relationships.

None.

Business experience.

Unless noted otherwise, each director has served in his or her present position for at least the past five years.

Susan N. Story – President and Chief Executive Officer since 2003. She previously served as Senior Vice President of Southern Power from November 2002 to April 2003; and Executive Vice President of SCS from January 2001 to April 2003.

C. LeDon Anchors – Attorney and President of Anchors Smith Grimsley, Attorneys at Law, Fort Walton Beach, Florida. He is a Director of Beach Community Bank.

William C. Cramer, Jr. - President and Owner of Tommy Thomas Chevrolet, Panama City, Florida.

Fred C. Donovan, Sr. - Chairman and Chief Executive Officer of Baskerville-Donovan, Inc. (an architectural and engineering firm), Pensacola, Florida.

William A. Pullum - Broker/President of Bill Pullum Realty, Inc., Navarre, Florida.

Winston E. Scott – Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas. He previously served as Executive Director of the Florida Space Authority, Cape Canaveral, Florida, from 2003 to 2006; Professor and Associate Dean with the Florida Agriculture and Mechanical University and Florida State University (FSU) College of Engineering in 2003, and Vice President for Student Affairs at FSU from 2000 until 2003.

Francis M. Fisher, Jr. - Vice President of Customer Operations since 1996.

P. Bernard Jacob - Vice President of External Affairs and Corporate Services since 2003. He previously served as Director of Information Resources Security and Program Management at SCS from 2002 to 2003; and Manager of Telecommunications Strategy at SCS from 1998 to 2002.

Ronnie R. Labrato - Vice President and Chief Financial Officer since January 14, 2006. He previously served as Vice President, Chief Financial Officer and Comptroller from 2001 to January 2006.

Penny M. Manuel - Vice President and Senior Production Officer since February 2005. She previously served as Director, Human Resources for Southern Company Generation from 2002 until February 2005; Vice President and Chief Information Officer, Alabama Power, and Regional Chief Information Officer for Southern Nuclear and SCS from 2001 until 2002.

Involvement in certain legal proceedings.
None.

Section 16(a) Beneficial Ownership Reporting Compliance.
None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics that applies to each director, officer and employee of the registrants and their subsidiaries. The code of business conduct and ethics can be found on Southern Company's website located at www.southerncompany.com. The code of business conduct and ethics is also available free of charge in print to any shareholder upon request. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance Guidelines and Committee Charters

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Governance Committee and Compensation and Management Succession Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder upon request.

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

Equity Compensation Plan Information

The following table provides information as of December 31, 2006 concerning shares of Southern Company's common stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	34,609,243(1)	$28.69	51,248,038(2)
Equity compensation plans not approved by security holders	N/A	N/A	N/A

(1) Includes shares available for future issuances under the Omnibus Incentive Compensation Plan, the 2006 Omnibus Incentive Compensation Plan and the Outside Directors Stock Plan.

(2) Includes shares available for future issuance under the 2006 Omnibus Incentive Compensation Plan approved May 24, 2006 (49,451,434) and the Outside Directors Stock Plan (1,796,604).

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2006 and 2005:

	2006	2005
	(in thousands)	
Gulf Power		
Audit Fees (1)	$1,076	$960
Audit-Related Fees	0	0
Tax Fees	0	0
All Other Fees	0	0
Total	$1,076	$960
Southern Power		
Audit Fees (1)	$1,106	$817
Audit-Related Fees	0	0
Tax Fees	0	0
All Other Fees	0	0
Total	$1,106	$817

(1) Includes services performed in connection with financing transactions.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2006 and 2005 (described in the footnote to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Report of Independent Registered Public Accounting Firm on Internal Control over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power and Subsidiary Companies are listed under Item 8 herein.

(2) Financial Statement Schedules:

Reports of Independent Registered Public Accounting Firm as to Schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power and Subsidiary Companies are included herein on pages IV-8, IV-9, IV-10, IV-11, IV-12 and IV-13.

Financial Statement Schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power and Subsidiary Companies are listed in the Index to the Financial Statement Schedules at page S-1.

(3) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: David M. Ratcliffe
Chairman, President and
Chief Executive Officer

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

David M. Ratcliffe
Chairman, President,
Chief Executive Officer and Director
(Principal Executive Officer)

Thomas A. Fanning
Executive Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita P. Baranco
Dorrit J. Bern
Thomas F. Chapman
Zack T. Pate
J. Neal Purcell
William G. Smith, Jr.
Gerald J. St. Pé

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Charles D. McCrary
President, Chief Executive Officer and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Philip C. Raymond
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
David J. Cooper, Sr.
Patricia M. King
Malcolm Portera
Robert D. Powers
David M. Ratcliffe
C. Dowd Ritter
James H. Sanford
John Cox Webb, IV

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: Michael D. Garrett
President and Chief Executive Officer

By: Wayne Boston

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Michael D. Garrett
President, Chief Executive Officer and Director
(Principal Executive Officer)

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Ann P. Daiss
Vice President, Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Gus H. Bell, III	*D. Gary Thompson*
Robert L. Brown, Jr.	*Richard W. Ussery*
Ronald D. Brown	*William Jerry Vereen*
David M. Ratcliffe	*E. Jenner Wood, III*

By: Wayne Boston

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: Susan N. Story
President and Chief Executive Officer

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Susan N. Story
President, Chief Executive Officer and Director
(Principal Executive Officer)

Ronnie R. Labrato
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

C. LeDon Anchors
William C. Cramer, Jr.
Fred C. Donovan, Sr.
William A. Pullum
Winston E. Scott

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Anthony J. Topazi
President and Chief Executive Officer

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Anthony J. Topazi
President, Chief Executive Officer and Director
(Principal Executive Officer)

Frances V. Turnage
Vice President, Treasurer and
Chief Financial Officer
(Principal Financial Officer)

Moses H. Feagin
Comptroller
(Principal Accounting Officer)

Directors:

Tommy E. Dulaney	*Aubrey B. Patterson, Jr.*
Warren A. Hood, Jr.	*George A. Schloegel*
Robert C. Khayat	*Philip J. Terrell*

By:

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Ronnie L. Bates
President and Chief Executive Officer

By: Wayne Boston

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Ronnie L. Bates
President, Chief Executive Officer and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

David B. DeBardelaben
Comptroller
(Principal Accounting Officer)

Directors:

William Paul Bowers — *G. Edison Holland, Jr.*
Thomas A. Fanning — *David M. Ratcliffe*

By: Wayne Boston

(Wayne Boston, Attorney-in-fact)

Date: February 26, 2007

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiary Companies (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and have issued our reports thereon dated February 26, 2007 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph concerning a change in method of accounting for the funded status of defined benefit pension and other postretirement plans in 2006); such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in the accompanying index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the financial statements of Alabama Power Company (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 26, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning a change in method of accounting for the funded status of defined benefit pension and other postretirement plans in 2006); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-3) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Birmingham, Alabama
February 26, 2007

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the financial statements of Georgia Power Company (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 26, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning a change in method of accounting for the funded status of defined benefit pension and other postretirement plans in 2006); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-4) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Gulf Power Company

We have audited the financial statements of Gulf Power Company (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 26, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning a change in method of accounting for the funded status of defined benefit pension and other postretirement plans in 2006); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-5) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 26, 2007 (which report expresses an unqualified opinion and includes an explanatory paragraph concerning a change in method of accounting for the funded status of defined benefit pension and other postretirement plans in 2006); such financial statements and report are included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-6) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Southern Power Company

We have audited the consolidated financial statements of Southern Power Company and subsidiaries (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and have issued our report thereon dated February 26, 2007; such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-7) listed in the accompanying index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2007

Member of
Deloitte Touche Tohmatsu

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INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules I through V not listed above are omitted as not applicable or not required. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts (a)					
2006	$37,510	$49,226	$1,230	$53,065 (b)	$34,901
2005	33,399	46,193	24	42,106 (b)	37,510
2004	15,812	54,248	2	36,663 (b)	33,399
Tax valuation allowance					
2006	$10,160	$53,164	$ -	$ -	$63,324
2005	5,237	4,923	-	-	10,160
2004	7,615	-	-	2,378	5,237

(a) Excludes provisions for uncollectible accounts in all periods for Southern Company Gas — a discontinued operation.
(b) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2006	$7,560	$14,130	$-	$14,599 (Note)	$7,091
2005	5,404	12,832	-	10,676 (Note)	7,560
2004	4,756	10,346	-	9,698 (Note)	5,404

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2006.	$ 9,563	$26,503	$-	$26,036 (Note)	$10,030
2005.	7,978	25,594	-	24,009 (Note)	9,563
2004.	6,167	21,391	-	19,580 (Note)	7,978
Tax valuation allowance					
2006.	$10,160	$53,164	$-	$ -	$63,324
2005.	5,237	4,923	-	-	10,160
2004.	7,615	-	-	2,378	5,237

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2006	$1,134	$2,612	$-	$2,467 (Note)	$1,279
2005	2,144	1,275	-	2,285 (Note)	1,134
2004	947	2,851	-	1,654 (Note)	2,144

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2006	$2,321	$1,071	$-	$2,537 (Note)	$ 855
2005	774	2,610	-	1,063 (Note)	2,321
2004	897	1,338	-	1,461 (Note)	774

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004
(Stated in Thousands of Dollars)

		Additions			
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2006	$ -	$-	$-	$ -	$ -
2005	350	-	-	350 (Note)	-
2004	350	-	-	-	350

Note: *Represents write-off of accounts receivable considered to be uncollectible, less recoveries of amounts previously written off.*

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EXHIBIT INDEX

The following exhibits indicated by an asterisk (*) preceding the exhibit number are filed herewith. The balance of the exhibits has heretofore been filed with the SEC as the exhibits and in the file numbers indicated and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 - Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through January 5, 1994. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A and in Certificate of Notification, File No. 70-8181, as Exhibit A.)

(a) 2 - By-laws of Southern Company as amended effective February 17, 2003, and as presently in effect. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3526, as Exhibit 3(a)1.)

Alabama Power

(b) 1 - Charter of Alabama Power and amendments thereto through December 12, 2006. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b) and in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2.)

(b) 2 - By-laws of Alabama Power as amended effective January 26, 2007, and as presently in effect. (Designated in Form 8-K dated January 26, 2007, File No 1-3164, as Exhibit 3(b)2.)

Georgia Power

(c) 1 - Charter of Georgia Power and amendments thereto through June 27, 2006. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2 and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1.)

(c) 2 - By-laws of Georgia Power as amended effective August 17, 2005, and as presently in effect. (Designated in Form 8-K dated August 17, 2005, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d) 1 - Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through November 16, 2005. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1 and in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7.)

(d) 2 - By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e) 1 - Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 0-6849, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 0-6849, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 0-6849, as Exhibit 3(e)2 and in Mississippi Power's Form 8-K dated March 3, 2004, File No. 0-6849, as Exhibit 4.6.)

(e) 2 - By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 0-6849, as Exhibit 3(e)2.)

Southern Power

(f) 1 - Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

(f) 2 - By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

Southern Company

(a) 1 - Subordinated Note Indenture dated as of February 1, 1997, among Southern Company, Southern Company Capital Funding, Inc. and Bank of New York Trust Company, N.A., as Successor Trustee, and indentures supplemental thereto dated as of February 4, 1997. (Designated in Registration Nos. 333-28349 as Exhibits 4.1 and 4.2 and 333-28355 as Exhibit 4.2.)

(a) 2 - Subordinated Note Indenture dated as of June 1, 1997, among Southern Company, Southern Company Capital Funding, Inc. and Bank of New York Trust Company, N.A., as Successor Trustee, and indentures supplemental thereto through July 31, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 1997, File No. 1-3526, as Exhibit 4(a)2, in Form 8-K dated June 18, 1998, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated December 18, 1998, File No. 1-3526, as Exhibit 4.4 and in Form 8-K dated July 24, 2002, File No. 1-3526, as Exhibit 4.4.)

(a) 3 - Senior Note Indenture dated as of February 1, 2002, among Southern Company, Southern Company Capital Funding, Inc. and The Bank of New York, as Trustee, and indentures supplemental thereto through November 16, 2005. (Designated in Form 8-K dated January 29, 2002, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated January 30, 2002, File No. 1-3526, as Exhibit 4.2 and in Form 8-K dated November 8, 2005, File No. 1-3526, as Exhibit 4.2.)

(a) 4 - Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indenture supplemental thereto dated as of January 18, 2007. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as Exhibits 4.1 and 4.2.)

(a) 5 - Amended and Restated Trust Agreement of Southern Company Capital Trust VI dated as of July 1, 2002. (Designated in Form 8-K dated July 24, 2002, File No. 1-3526, as Exhibit 4.7-A.)

(a) 6 - Preferred Securities Guarantee Agreement relating to Southern Company Capital Trust VI dated as of July 1, 2002. (Designated in Form 8-K dated July 24, 2002, File No. 1-3526, as Exhibit 4.11-A.)

Alabama Power

(b) 1 - Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 3164, as Exhibit 4.2 and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b) 2 - Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through February 6, 2007. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2 and in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2.)

(b) 3 - Amended and Restated Trust Agreement of Alabama Power Capital Trust IV dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-A.)

(b) 4 - Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 5 - Guarantee Agreement relating to Alabama Power Capital Trust IV dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-A.)

(b) 6 - Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 - Subordinated Note Indenture dated as of June 1, 1997, between Georgia Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through January 23, 2004. (Designated in Certificate of Notification, File No. 70-8461, as Exhibits D and E, in Form 8-K dated February 17, 1999, File No. 1-6468, as Exhibit 4.4, in Form 8-K dated June 13, 2002, File No. 1-6468, as

Exhibit 4.4, in Form 8-K dated October 30, 2002, File No. 1-6468, as Exhibit 4.4 and in Form 8-K dated January 15, 2004, File No. 1-6468, as Exhibit 4.4.)

(c) 2 - Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through December 13, 2006. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1 and in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2.)

(c) 3 - Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York, as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated December 2, 2004, File No. 1-5072, as Exhibit 4.1 and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

(c) 4 - Amended and Restated Trust Agreement of Georgia Power Capital Trust V dated as of June 1, 2002. (Designated in Form 8-K dated June 13, 2002, as Exhibit 4.7-A.)

(c) 5 - Amended and Restated Trust Agreement of Georgia Power Capital Trust VI dated as of November 1, 2002. (Designated in Form 8-K dated October 30, 2002, as Exhibit 4.7-A.)

(c) 6 - Amended and Restated Trust Agreement of Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.7-A.)

(c) 7 - Guarantee Agreement relating to Georgia Power Capital Trust V dated as of June 1, 2002. (Designated in Form 8-K dated June 13, 2002, as Exhibit 4.11-A.)

(c) 8 - Guarantee Agreement relating to Georgia Power Capital Trust VI dated as of November 1, 2002. (Designated in Form 8-K dated October 30, 2002, as Exhibit 4.11-A.)

(c) 9 - Guarantee Agreement relating to Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.11-A.)

Gulf Power

(d) 1 - Subordinated Note Indenture dated as of January 1, 1997, between Gulf Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through December 13, 2002. (Designated in Form 8-K dated January 27, 1997, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated July 28, 1997, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 13, 1998, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated November 8, 2001, File No. 0-2429, as Exhibit 4.2 and in Form 8-K dated December 5, 2002, File No. 0-2429, as Exhibit 4.2.)

(d) 2 - Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through December 6, 2006. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 4.1 and in Form 8-K dated November 28, 2006, File No. 0-2429, as Exhibit 4.2.)

(d) 3 - Amended and Restated Trust Agreement of Gulf Power Capital Trust III dated as of November 1, 2001. (Designated in Form 8-K dated November 8, 2001, File No. 0-2429, as Exhibit 4.5.)

(d) 4 - Amended and Restated Trust Agreement of Gulf Power Capital Trust IV dated as of December 1, 2002. (Designated in Form 8-K dated December 5, 2002, File No. 0-2429, as Exhibit 4.5.)

(d) 5 - Guarantee Agreement relating to Gulf Power Capital Trust III dated as of November 1, 2001. (Designated in Form 8-K dated November 8, 1998, File No. 0-2429, as Exhibit 4.8.)

(d) 6 - Guarantee Agreement relating to Gulf Power Capital Trust IV dated as of December 1, 2002. (Designated in Form 8-K dated December 5, 2002, File No. 0-2429, as Exhibit 4.8.)

Mississippi Power

(e) 1 - Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as Trustee, and indentures supplemental thereto through June 30, 2005. (Designated in Form 8-K dated May 14, 1998, File No. 0-6849, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 0-6849, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 0-6849, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2 and in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2.)

(e) 2 - Subordinated Note Indenture dated as of February 1, 1997, between Mississippi Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as Trustee, and indenture supplemental thereto dated as of March 22, 2002. (Designated in Form 8-K dated February 20, 1997, File No. 0-6849, as Exhibits 4.1 and 4.2 and in Form 8-K dated March 15, 2002, File No. 0-6849, as Exhibit 4.5.)

(e) 3 - Amended and Restated Trust Agreement of Mississippi Power Capital Trust II dated as of March 1, 2002. (Designated in Form 8-K dated March 15, 2002, File No. 0-6849, as Exhibit 4.5.)

(e) 4 - Guarantee Agreement relating to Mississippi Power Capital Trust II dated as of March 1, 2002. (Designated in Form 8-K dated March 15, 2002, File No. 0-6849, as Exhibit 4.8.)

Southern Power

(f) 1 - Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York, as Trustee, and indentures supplemental thereto through November 21, 2006. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1 and in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2.)

(10) Material Contracts

Southern Company

\# (a) 1 - Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2006. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2006, File No. 1-3526, as Exhibit 10(a)1.)

\# (a) 2 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2006, File No. 1-3526, as Exhibit 10(a)2.)

\# (a) 3 - Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective February 19, 2001. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)59.)

\# (a) 4 - Southern Company Deferred Compensation Plan as amended and restated January 1, 2005. (Designated in Southern Company's Form 10-Q for the quarter ended September 30, 2006, File No. 1-3526, as Exhibit 10(a)1.)

\# (a) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

\# (a) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective May 1, 2000 and First Amendment thereto. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)62 and in Southern Company's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3526, as Exhibit 10(a)2.)

\# (a) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective May 1, 2000 and First and Second Amendments thereto. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)64, in Southern Company's Form 10-Q for the quarter ended September 30, 2003, File No. 1-3526, as Exhibit 10(a)3 and in Southern Company's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3526, as Exhibit 10(a)3.)

\# (a) 8 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, SCS and G. Edison Holland, Jr. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.5.)

\# (a) 9 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, Alabama Power and Charles D. McCrary. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.6.)

\# (a) 10 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, SCS and David M. Ratcliffe. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.2.)

\# (a) 11 - Southern Company Change in Control Benefits Protection Plan, effective November 16, 2006. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.1.)

\# (a) 12 - Master Separation and Distribution Agreement dated as of September 1, 2000 between Southern Company and Mirant. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)100.)

\# (a) 13 - Indemnification and Insurance Matters Agreement dated as of September 1, 2000 between Southern Company and Mirant. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)101.)

\# (a) 14 - Tax Indemnification Agreement dated as of September 1, 2000 among Southern Company and its affiliated companies and Mirant and its affiliated companies. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)102.)

\# (a) 15 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia

Power, Gulf Power, Mississippi Power, Southern Communications, Energy Solutions and Southern Nuclear. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103.)

(a) 16 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104.)

(a) 17 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92.)

(a) 18 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, SCS and Thomas A. Fanning. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.3.)

(a) 19 - Supplemental Pension Agreement between Georgia Power, Gulf Power, SCS and G. Edison Holland, Jr. effective February 22, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 2002, File No. 1-3526, as Exhibit 10(a)119.)

(a) 20 - Southern Company Senior Executive Change in Control Severance Plan effective May 1, 2003. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3526, as Exhibit 10(a)3.)

(a) 21 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective May 1, 2003. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3526, as Exhibit 10(a)(2).)

(a) 22 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, Georgia Power and Michael D. Garrett. (Designated in Form 8-K dated November 16, 2006, File No. 1-3526, as Exhibit 10.4.)

* (a) 23 - Base Salaries of Named Executive Officers.

(a) 24 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Southern Company's Form 10-Q for the quarter ended September 30, 2006, File No. 1-3526, as Exhibit 10(a)2.)

Alabama Power

(b) 1 - Interchange contract dated February 17, 2000, between Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and SCS. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)6.)

(b) 2 - Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2006. See Exhibit 10(a)1 herein.

(b) 3 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(b) 4 - Southern Company Deferred Compensation Plan as amended and restated January 1, 2005. See Exhibit 10(a)4 herein.

(b) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(b) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective May 1, 2000 and First Amendment thereto. See Exhibit 10(a)6 herein.

(b) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective May 1, 2000 and First and Second Amendments thereto. See Exhibit 10(a)7 herein.

(b) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective May 1, 2003. See Exhibit 10(a)21 herein.

(b) 9 - Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2001. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 10(b)28.)

(b) 10 - Southern Company Change in Control Benefits Protection Plan, effective November 16, 2006. See Exhibit 10(a)11 herein.

(b) 11 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Communications, Energy Solutions and Southern Nuclear. See Exhibit 10(a)15 herein.

(b) 12 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)16 herein.

(b) 13 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)17 herein.

(b) 14 - Southern Company Senior Executive Change in Control Severance Plan effective May 1, 2003. See Exhibit 10(a)20 herein.

(b) 15 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, Alabama Power and Charles D. McCrary. See Exhibit 10(a)9 herein.

(b) 16 - Amended and Restated Change in Control Agreement between Southern Company, Alabama Power and C. Alan Martin, effective June 1, 2004. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(b)4.)

* (b) 17 - Base Salaries of Named Executive Officers.

(b) 18 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2004, File No. 1-3164, as Exhibit 10(b)20.)

Georgia Power

(c) 1 - Interchange contract dated February 17, 2000, between Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and SCS. See Exhibit 10(b)1 herein.

(c) 2 - Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)

(c) 3 - Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)

(c) 4 - Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)

(c) 5 - Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2006. See Exhibit 10(a)1 herein.

(c) 6 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(c) 7 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2005. See Exhibit 10(a)4 herein.

(c) 8 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(c) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective May 1, 2000 and First Amendment thereto. See Exhibit 10(a)6 herein.

(c) 10 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective May 1, 2000 and First and Second Amendments thereto. See Exhibit 10(a)7 herein.

(c) 11 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective May 1, 2003. See Exhibit 10(a)21 herein.

(c) 12 - Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 13, 2003. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2002, File No. 1-6468, as Exhibit 10(c)68.)

(c) 13 - Southern Company Change in Control Benefits Protection Plan, effective November 16, 2006. See Exhibit 10(a)11 herein.

(c) 14 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Communications, Energy Solutions and Southern Nuclear. See Exhibit 10(a)15 herein.

(c) 15 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)16 herein.

(c) 16 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)17 herein.

(c) 17 - Southern Company Senior Executive Change in Control Severance Plan effective May 1, 2003. See Exhibit 10(a)20 herein.

(c) 18 - 1997 Deferred Compensation Plan for Directors of Savannah Electric, Amended and Restated effective October 26, 2000. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 2000, File No. 1-5072 as Exhibit 10(f)18.)

(c) 19 - Deferred Compensation Agreement between Southern Company, SCS and Christopher C. Womack dated May 31, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 2002, File No. 1-3526, as Exhibit 10(a)118.)

(c) 20 - Amended and Restated Supplemental Pension Agreement among SCS, Southern Nuclear, Alabama Power and James H. Miller, III. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3164, as Exhibit 10(b)1.)

(c) 21 - Amended and Restated Change in Control Agreement dated November 16, 2006 between Southern Company, Georgia Power and Michael D. Garrett. See Exhibit 10(a)22 herein.

(c) 22 - Separation Agreement, dated as of January 4, 2006, between Georgia Power and William C. Archer III. (Designated in Form 8-K dated January 4, 2006, File No. 1-6468, as Exhibit 10.1.)

(c) 23 - Consulting Agreement, dated as of January 4, 2006, between Georgia Power and William C. Archer III. (Designated in Form 8-K dated January 4, 2006, File No. 1-6468, as Exhibit 10.2.)

(c) 24 - Supplemental Pension Agreement between Georgia Power, Gulf Power, SCS and G. Edison Holland, Jr. effective February 22, 2002. See Exhibit 10(a)19 herein.

* (c) 25 - Base Salaries of Named Executive Officers.

(c) 26 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2004, File No. 1-6468, as Exhibit 10(c)24.)

Gulf Power

(d) 1 - Interchange contract dated February 17, 2000, between Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and SCS. See Exhibit 10(b)1 herein.

(d) 2 - Unit Power Sales Agreement dated July 19, 1988, between FPC and Alabama Power, Georgia Power, Gulf Power, Mississippi Power and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(d).)

(d) 3 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and Alabama Power, Georgia Power, Gulf Power, Mississippi Power and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(e).)

(d) 4 - Amended Unit Power Sales Agreement dated August 17, 1988, between JEA and Alabama Power, Georgia Power, Gulf Power, Mississippi Power and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(f).)

(d) 5 - Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2006. See Exhibit 10(a)1 herein.

(d) 6 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(d) 7 - Southern Company Deferred Compensation Plan as amended and restated January 1, 2005. See Exhibit 10(a)4 herein.

(d) 8 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(d) 9 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective May 1, 2000 and First and Second Amendments thereto. See Exhibit 10(a)7 herein.

(d) 10 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective May 1, 2003. See Exhibit 10(a)21 herein.

(d) 11 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective May 1, 2000 and First Amendment thereto. See Exhibit 10(a)6 herein.

(d) 12 - Deferred Compensation Plan For Directors of Gulf Power Company, Amended and Restated effective January 1, 2000 and First Amendment thereto. (Designated in Gulf Power's Form 10-K for the year ended December 31, 2000, File No. 0-2429 as Exhibit 10(d)33.)

(d) 13 - Southern Company Change in Control Benefits Protection Plan, effective November 16, 2006. See Exhibit 10(a)11 herein.

(d) 14 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Communications, Energy Solutions and Southern Nuclear. See Exhibit 10(a)15 herein.

(d) 15 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)16 herein.

(d) 16 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)17 herein.

(d) 17 - Southern Company Senior Executive Change in Control Severance Plan effective May 1, 2003. See Exhibit 10(a)20 herein.

* (d) 18 - Base Salaries of Named Executive Officers.

(d) 19 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-K for the year ended December 31, 2004, File No. 0-2429, as Exhibit 10(d)20.)

Mississippi Power

(e) 1 - Interchange contract dated February 17, 2000, between Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and SCS. See Exhibit 10(b)1 herein.

(e) 2 - Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 0-6849, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 0-6849, as Exhibit 10(f)(2) and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 0-6849, as Exhibit 10(f)(3).)

(e) 3 - Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2006. See Exhibit 10(a)1 herein.

(e) 4 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(e) 5 - Southern Company Deferred Compensation Plan as amended and restated January 1, 2005. See Exhibit 10(a)4 herein.

(e) 6 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(e) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective May 1, 2000 and First and Second Amendments thereto. See Exhibit 10(a)7 herein.

(e) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective May 1, 2003. See Exhibit 10(a)21 herein.

(e) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective May 1, 2000 and First Amendment thereto. See Exhibit 10(a)6 herein.

(e) 10 - Deferred Compensation Plan for Directors of Mississippi Power Company, Amended and Restated effective January 1, 2000 and Amendment Number One thereto. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1999, File No. 0-6849 as Exhibit 10(e)37 and in Mississippi Power's Form 10-K for the year December 31, 2000, File No. 0-6849 as Exhibit 10(e)30.)

(e) 11 - Southern Company Change in Control Benefits Protection Plan, effective November 16, 2006. See Exhibit 10(a)11 herein.

(e) 12 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Communications, Energy Solutions and Southern Nuclear. See Exhibit 10(a)15 herein.

(e) 13 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)16 herein.

(e) 14 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power and Mississippi Power. See Exhibit 10(a)17 herein.

(e) 15 - Southern Company Senior Executive Change in Control Severance Plan effective May 1, 2003. See Exhibit 10(a)20 herein.

* (e) 16 - Base Salaries of Named Executive Officers.

(e) 17 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2004, File No. 001-11229, as Exhibit 10(e)20.)

Southern Power

(f) 1 - Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)

(f) 2 - Interchange contract dated February 17, 2000, between Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and SCS. See Exhibit 10(b)1 herein.

(f) 3 - Amended and Restated Operating Agreement between Southern Power and Alabama Power effective December 1, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 2003, File No. 1-3526, as Exhibit 10(a)61.)

(f) 4 - Amended and Restated Operating Agreement between Southern Power and Georgia Power effective December 1, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 2003, File No. 1-3526, as Exhibit 10(a)62.)

(f) 5 - Power Purchase Agreement between Southern Power and Alabama Power dated as of June 1, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.18.)

(f) 6 - Amended and Restated Power Purchase Agreement between Southern Power and Georgia Power at Plant Autaugaville dated as of August 6, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.19.)

(f) 7 - Contract for the Purchase of Firm Capacity and Energy between Southern Power and Georgia Power dated as of July 26, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.21.)

(f) 8 - Power Purchase Agreement between Southern Power and Georgia Power at Plant Goat Rock dated as of March 30, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.22.)

(f) 9 - Purchase and Sale Agreement, by and between CP Oleander, LP and CP Oleander I, Inc., as Sellers, Constellation Power, Inc. and SP Newco I LLC and SP Newco II LLC, as Purchasers, and Southern Power, as Purchaser's Parent, for the Sale of Partnership Interests of Oleander Power Project, LP, dated as of April 8, 2005. (Designated in Form 8-K dated June 7, 2005, File No. 333-98553, as Exhibit 2.1)

(f) 10 - Cooperative Agreement between the DOE and SCS dated as of February 22, 2006. (Designated in Southern Power's Form 10-K for the year ended December 31, 2005, File No. 333-98553, as Exhibit 10(g)11.) (Southern Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)

(f) 11 - Multi-Year Credit Agreement dated as of July 7, 2006 by and among Southern Power, the Lenders (as defined therein), Citibank, N.A., as Administrative Agent, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Initial Issuing Bank. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)1.) (Omits schedules and exhibits. Southern Power agreed to provide supplementally the omitted schedules and exhibits to the SEC upon request.)

(f) 12 - Purchase and Sale Agreement by and between Progress Genco Ventures, LLC and Southern Power Company - DeSoto LLC dated May 8, 2006. (Designated in Form 8-K dated May 31, 2006, File No. 333-98553, as Exhibit 2.1.) (Omits schedules and exhibits. Southern Power agreed to provide supplementally the omitted schedules and exhibits to the SEC upon request.) (Southern Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)

(f) 13 - Assignment and Assumption Agreement between Southern Power Company - Desoto LLC and Southern Power effective May 24, 2006. (Designated in Form 8-K dated May 31, 2006, File No. 333-98553, as Exhibit 2.2.)

(f) 14 - Purchase and Sale Agreement by and between Progress Genco Ventures, LLC and Southern Power Company - Rowan LLC dated May 8, 2006. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)4.) (Omits schedules and exhibits.

Southern Power agrees to provide supplementally the omitted schedules and exhibits to the SEC upon request.) (Southern Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)

(f) 15 - Assignment and Assumption Agreement between Southern Power Company - Rowan LLC and Southern Power effective May 24, 2006. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)5.)

(14) Code of Ethics

Southern Company

(a) - The Southern Company Code of Ethics. (Designated in Southern Company's Form 10-K for the year ended December 31, 2003, File No. 1-3526, as Exhibit 14(a).)

Alabama Power

(b) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) - Subsidiaries of Registrant.

Alabama Power

(b) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

(c) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 - Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 - Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 - Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 - Consent of Deloitte & Touche LLP.

Mississippi Power

* (e) 1 - Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 - Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) - Power of Attorney and resolution.

Alabama Power

* (b) - Power of Attorney and resolution.

Georgia Power

* (c) - Power of Attorney and resolution.

Gulf Power

* (d) - Power of Attorney and resolution.

Mississippi Power

* (e) - Power of Attorney and resolution.

Southern Power

* (f) - Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

* (a) 1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a) 2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) 1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (b) 2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) 1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (c) 2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) 1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (d) 2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) 1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (e) 2 - Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) 1 - Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (f) 2 - Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

* (a) - Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) - Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) - Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) - Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) - Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) - Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

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