GULF POWER COMPANY

2014 ANNUAL REPORT

GULF POWER

A SOUTHERN COMPANY

CONTENTS
Gulf Power Company 2014 Annual Report

SUMMARY

	2014	**2013**	Percent Change
Financial Highlights *(in thousands)*:			
Operating revenues	**$1,590,482**	**$1,440,301**	10.4
Operating expenses	**1,309,267**	**1,175,298**	11.4
Net income after dividends on preference stock	**140,176**	**124,429**	12.7
Gross property additions	**360,937**	**304,778**	18.4
Total assets	**4,708,259**	**4,337,571**	8.5
Operating Data:			
Kilowatt-hour sales *(in thousands)*:			
Retail	**11,075,062**	**10,619,887**	4.3
Sales for resale - non-affiliates	**1,670,121**	**1,162,308**	43.7
Sales for resale - affiliates	**3,283,685**	**3,127,350**	5.0
Total	**16,028,868**	**14,909,545**	7.5
Customers served at year-end	**444,047**	**439,389**	1.1
Peak-hour demand, net *(in megawatts)*	**2,684**	**2,356**	13.9
Capitalization Ratios *(percent)*:			
Common stock equity	**46.3**	**48.6**	
Preference stock	**5.2**	**5.8**	
Long-term debt (excluding amounts due within one year)	**48.5**	**45.6**	
Return on Average Common Equity *(percent)*	**11.02**	**10.30**	

[This page intentionally left blank]

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2014 Annual Report

The management of Gulf Power Company (the Company) 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 the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

S. W. Connally, Jr.
President and Chief Executive Officer

Richard S. Teel
Vice President and Chief Financial Officer

March 2, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
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 The Southern Company) as of December 31, 2014 and 2013, 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, 2014. 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 27 to 65) present fairly, in all material respects, the financial position of Gulf Power Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
March 2, 2015

DEFINITIONS

Term	Meaning
AFUDC	Allowance for funds used during construction
Alabama Power	Alabama Power Company
ASC	Accounting Standards Codification
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GAAP	Generally accepted accounting principles
Georgia Power	Georgia Power Company
IRS	Internal Revenue Service
ITC	Investment tax credit
KWH	Kilowatt-hour
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MW	Megawatt
OCI	Other comprehensive income
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
scrubber	Flue gas desulfurization system
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, Southern Electric Generating Company, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power

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 constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, restoration following major storms, and fuel. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

In December 2013, the Florida PSC voted to approve the settlement agreement (Settlement Agreement) among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); (3) may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017; and (4) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail Base Rate Case" herein for additional details of the Settlement Agreement.

Key Performance Indicators

The Company continues to focus on several key performance indicators including customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance, which the Company achieved in 2014.

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. The Company's 2014 Peak Season EFOR of 0.98% was better than the target. 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. The Company's performance for 2014 was better than the target for these transmission and distribution reliability measures.

The Company uses net income after dividends on preference stock as the primary measure of the Company's financial performance. In 2014, the Company achieved its targeted net income after dividends on preference stock. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2014 net income after dividends on preference stock was $140.2 million, representing a $15.8 million, or 12.7%, increase over the previous year. The increase was primarily due to higher retail revenues, partially offset by higher other operations and maintenance expenses as compared to the corresponding period in 2013.

In 2013, net income after dividends on preference stock was $124.4 million, representing a $1.5 million, or 1.2%, decrease from the previous year. The decrease was primarily due to an increase in depreciation and dividends on preference stock, partially offset by decreases in other operations and maintenance expenses and interest expense as compared to the corresponding period in 2012.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year	
	2014	**2014**	2013
		(in millions)	
Operating revenues	**$ 1,590.5**	**$ 150.2**	$ 0.6
Fuel	**604.6**	**71.8**	(12.1)
Purchased power	**107.2**	**21.9**	11.2
Other operations and maintenance	**341.2**	**31.4**	(4.3)
Depreciation and amortization	**145.0**	**(4.0)**	8.0
Taxes other than income taxes	**111.2**	**12.8**	1.0
Total operating expenses	**1,309.2**	**133.9**	3.8
Operating income	**281.3**	**16.3**	(3.2)
Total other income and (expense)	**(44.0)**	**9.2**	3.7
Income taxes	**88.1**	**8.4**	0.5
Net income	**149.2**	**17.1**	—
Dividends on preference stock	**9.0**	**1.3**	1.5
Net income after dividends on preference stock	**$ 140.2**	**$ 15.8**	$ (1.5)

Operating Revenues

Operating revenues for 2014 were $1.59 billion, reflecting an increase of $150.2 million from 2013. The following table summarizes the significant changes in operating revenues for the past two years:

	Amount	
	2014	2013
	(in millions)	
Retail — prior year	**$ 1,170.0**	$ 1,144.5
Estimated change resulting from –		
Rates and pricing	**47.1**	0.1
Sales growth (decline)	**8.2**	(1.4)
Weather	**9.4**	(0.3)
Fuel and other cost recovery	**31.8**	27.1
Retail — current year	**1,266.5**	1,170.0
Wholesale revenues –		
Non-affiliates	**129.2**	109.4
Affiliates	**130.1**	99.6
Total wholesale revenues	**259.3**	209.0
Other operating revenues	**64.7**	61.3
Total operating revenues	**$ 1,590.5**	$ 1,440.3
Percent change	**10.4%**	—%

In 2014, retail revenues increased $96.5 million, or 8.3%, when compared to 2013 primarily as a result of higher fuel cost recovery revenues and higher revenues resulting from an increase in retail base rates effective January 2014, as approved by the Florida PSC. In 2013, retail revenues increased $25.5 million, or 2.2%, when compared to 2012 primarily as a result of higher fuel revenues and energy conservation cost recovery revenues. The increase in fuel revenues was partially offset by a payment received during 2013 pursuant to the resolution of a coal contract dispute. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (or decline) and weather.

In 2014, revenues associated with changes in rates and pricing included higher revenues due to an increase in retail base rates and revenues associated with higher rates under the Company's environmental cost recovery clause. In 2013, revenues associated with changes in rates and pricing were relatively flat as a result of higher revenues due to increases in retail base rates, partially offset by lower rates under the Company's energy conservation cost recovery clause and the environmental cost recovery clause. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, and the difference between projected and actual costs and revenues related to energy conservation and environmental compliance. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate case and cost recovery clauses, including the Company's fuel cost recovery, purchased power capacity recovery, environmental cost recovery, and energy conservation cost recovery clauses.

Wholesale revenues from power sales to non-affiliated utilities were as follows:

	2014	2013	2012
		(in millions)	
Capacity and other	**$ 65.1**	$ 64.0	$ 68.2
Energy	**64.1**	45.4	38.7
Total non-affiliated	**$ 129.2**	$ 109.4	$ 106.9

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. See FUTURE EARNINGS POTENTIAL – "General" for additional information.

In 2014, wholesale revenues from sales to non-affiliates increased $19.8 million, or 18.1%, as compared to the prior year primarily due to a 43.7% increase in KWH sales as a result of lower-priced energy supply alternatives from the Southern Company system's resources and fewer planned outages at Plant Scherer Unit 3 partially offset by a 1.9% decrease in the price of energy sold to non-affiliates due to the lower cost of fuel per KWH generated. In 2013, wholesale revenues from sales to non-affiliates increased $2.5 million, or 2.3%, as compared to the prior year primarily due to an 18.9% increase in KWH sales as a result of more energy scheduled by wholesale customers to serve their loads. This increase was partially offset by a 6.2% decrease in capacity revenues reflecting contractual reductions for changes in environmental costs.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2014, wholesale revenues from sales to affiliates increased $30.5 million, or 30.7%, as compared to the prior year primarily due to a 24.5% increase in the price of energy sold to affiliates due to higher marginal generation costs and a 5.0% increase in KWH sales as a result of an increase of the Company's generation dispatched to serve affiliated companies' higher weather-related energy demand primarily in the first and third quarters of 2014. In 2013, wholesale revenues from sales to affiliates decreased $24.1 million, or 19.5%, as compared to the prior year primarily due to lower energy revenues related to a 28.4% decrease in KWH sales that resulted from less Company generation being dispatched to serve affiliated companies' demand. This decrease in 2013 was partially offset by a 12.7% increase in the price of energy sold to affiliates in 2013.

Other operating revenues increased $3.4 million, or 5.5%, in 2014 as compared to the prior year primarily due to a $4.5 million increase in franchise fees due to increased retail revenues, partially offset by a $2.3 million decrease in revenues from other energy services. In 2013, other operating revenues decreased $3.4 million, or 5.3%, as compared to the prior year primarily due to a $5.4 million decrease in revenues from other energy services, partially offset by a $1.9 million increase in transmission revenues. Franchise fees have no impact on net income. Revenues from other energy services did not have a material effect on net income since they were generally offset by associated expenses.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2014 and the percent change from the prior year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2014	**2014**	2013	**2014**	2013
	(in millions)				
Residential	**5,363**	**5.4%**	0.7 %	**1.3%**	0.5 %
Commercial	**3,838**	**0.7**	(1.3)	**0.1**	(0.4)
Industrial	**1,849**	**8.8**	(1.4)	**8.8**	(1.4)
Other	**25**	**20.5**	(17.1)	**20.5**	(17.1)
Total retail	**11,075**	**4.3**	(0.4)	**2.1%**	(0.2)%
Wholesale					
Non-affiliates	**1,670**	**43.7**	18.9		
Affiliates	**3,284**	**5.0**	(28.4)		
Total wholesale	**4,954**	**15.5**	(19.8)		
Total energy sales	**16,029**	**7.5%**	(6.9)%		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth. Residential KWH sales increased in 2013 compared to 2012 primarily due to customer growth.

Commercial KWH sales increased in 2014 compared to 2013 primarily due to colder weather in the first quarter of 2014 and customer growth, partially offset by a decline in weather-adjusted use per customer. Commercial KWH sales decreased in 2013 compared to 2012 primarily due to milder weather in 2013 compared to 2012 and a decline in weather-adjusted use per customer, partially offset by customer growth.

Industrial KWH sales increased in 2014 compared to 2013 primarily due to decreased customer co-generation and changes in customers' operations. Industrial KWH sales decreased in 2013 compared to 2012 primarily due to changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

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, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's generation and purchased power were as follows:

	2014	2013	2012
Total generation *(millions of KWHs)*	**11,109**	9,216	9,648
Total purchased power *(millions of KWHs)*	**5,547**	6,298	6,952
Sources of generation *(percent)* –			
Coal	**67**	61	60
Gas	**33**	39	40
Cost of fuel, generated *(cents per net KWH)* –			
Coal[(a)]	**4.03**	4.12	4.42
Gas	**3.93**	3.95	3.96
Average cost of fuel, generated *(cents per net KWH)*[(a)]	**3.99**	4.05	4.23
Average cost of purchased power *(cents per net KWH)*[(b)]	**4.83**	3.88	3.03

(a) 2013 cost of coal includes the effect of a payment received pursuant to the resolution of a coal contract dispute.
(b) Average cost of purchased power includes fuel purchased by the Company for tolling agreements where power is generated by the provider.

In 2014, total fuel and purchased power expenses were $711.8 million, an increase of $93.7 million, or 15.2%, from the prior year costs. Total fuel and purchased power expenses for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the higher volume of KWHs generated and purchased increased expenses $54.9 million primarily due to increased Company owned generation dispatched to serve higher Southern Company system demand as a result of colder weather in the first quarter and warmer weather in the third quarter 2014. The increased expenses also included an $18.3 million increase due to a higher average cost of fuel and purchased power.

In 2013, total fuel and purchased power expenses were $618.1 million, a decrease of $0.9 million, or 0.2%, from the prior year costs. The decrease in fuel and purchased power expenses was due to a $37.3 million decrease in the volume of KWHs generated and purchased, partially offset by a $36.4 million increase in the average cost of fuel and purchased power which included a payment received during 2013 pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel and purchased power increased $57.0 million.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel cost, purchased power capacity recovery clauses, and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $604.6 million in 2014, an increase of $71.8 million, or 13.5%, from the prior year costs. The increase was primarily due to a 20.5% higher volume of KWHs generated primarily due to increased generation dispatched to serve higher Southern Company system loads due to colder weather in the first quarter 2014 and warmer weather in the third quarter 2014. The fuel expense for 2013 included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated decreased 6.8%. In 2013, fuel expense was $532.8 million, a decrease of $12.1 million, or 2.2%, from the prior year costs. The decrease was primarily due to a 4.3% decrease in the average cost of fuel per KWH generated which included a 2013 payment received pursuant to the resolution of a coal contract dispute. Excluding the payment, the average cost of fuel per KWH generated increased 1.2%.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $82.0 million in 2014, an increase of $29.6 million, or 56.3%, from the prior year. The increase was due to a 37.3% increase in the average cost per KWH purchased, which included a $28.4 million increase in capacity costs associated with a scheduled price increase for an existing PPA, partially offset by the expiration of another PPA. This increase was partially offset by a 16.3% decrease in the volume of KWHs purchased due to colder regional weather conditions in the first quarter 2014 which limited the availability of market resources. In 2013, purchased power expense from non-affiliates was $52.4 million, an increase of $1.0 million, or 2.0%, from the prior year. The increase was due to a 31.5% increase in the average cost per KWH purchased, partially offset by a 13.8% decrease in the volume of KWHs purchased.

Energy purchases from non-affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation.

Purchased Power – Affiliates

Purchased power expense from affiliates was $25.2 million in 2014, a decrease of $7.7 million, or 23.1%, from the prior year. The decrease was primarily due to a 43.3% decrease in the average cost per KWH purchased, which included a $13.5 million reduction in capacity costs primarily associated with the expiration of an existing PPA. This decrease was partially offset by a 33.2% increase in the volume of KWHs purchased primarily due to higher planned outages for the Company's generating units in the fourth quarter 2014. In 2013, purchased power expense from affiliates was $32.9 million, an increase of $10.2 million, or 44.9%, from the prior year. The increase was primarily due to a 93.4% increase in the volume of KWHs purchased, partially offset by a 30.2% decrease in the average cost per KWH purchased.

Energy purchases from affiliates will vary depending on demand and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, all as approved by the FERC.

Other Operations and Maintenance Expenses

In 2014, other operations and maintenance expenses increased $31.4 million, or 10.1%, compared to the prior year primarily due to increases in routine and planned maintenance expenses at generation, transmission and distribution facilities.

In 2013, other operations and maintenance expenses decreased $4.3 million, or 1.4%, compared to the prior year primarily due to decreases of $14.4 million in routine and planned maintenance expenses at generation facilities related to decreases in scheduled outages and cost containment efforts in 2013 and $4.9 million in other energy services expenses, partially offset by increases of $5.1 million in pension and other benefit-related expenses, $4.9 million in transmission service related to a third party PPA, $2.2 million in distribution system maintenance primarily due to increased vegetation management and $2.1 million in marketing incentive programs. Expenses from other energy services did not have a significant impact on earnings since they were generally offset by associated revenues. Expenses from transmission service did not have a significant impact on earnings since this expense was offset by purchased power capacity revenues through the Company's purchased power capacity recovery clause. Expenses from marketing incentive programs did not have a significant impact on earnings since the expense was offset by energy conservation revenues through the Company's energy conservation cost recovery clause. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses," and Notes 1 and 3 to the financial statements under "Affiliate Transactions" and "Cost Recovery Clauses," respectively, for additional information.

Depreciation and Amortization

Depreciation and amortization decreased $4.0 million, or 2.7%, in 2014 compared to the prior year. As authorized by the Florida PSC in the Settlement Agreement, the Company recorded an $8.4 million reduction in depreciation expense in 2014. This decrease was partially offset by increases of $4.4 million in depreciation and amortization primarily attributable to property additions at generation, transmission, and distribution facilities. In 2013, depreciation and amortization increased $8.0 million, or 5.7%, compared to the prior year primarily attributable to equipment replacements completed on Plant Crist Unit 7 and other additions to transmission and distribution facilities. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $12.8 million, or 13.0%, in 2014 compared to the prior year primarily due to increases of $4.4 million in franchise fees and $4.0 million in gross receipts taxes as a result of higher retail revenues as well as a $2.7 million increase in property taxes. In 2013, taxes other than income taxes increased $1.0 million, or 1.1%, compared to the prior year primarily due to a $2.8 million increase in property taxes, partially offset by decreases of $0.7 million in gross receipts taxes, $0.7 million in payroll taxes, and $0.4 million in franchise fees. Gross receipts taxes and franchise fees have no impact on net income.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $5.6 million, or 86.4%, in 2014 compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities and transmission projects. In 2013, AFUDC equity increased $1.2 million, or 23.5%, compared to the prior year primarily due to increased construction projects related to environmental control projects at generation facilities. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $2.8 million, or 5.0%, in 2014 compared to the prior year primarily due to an increase in capitalization of AFUDC debt related to the construction of environmental control projects and lower interest rates on pollution control bonds, offset by increases in long term debt resulting from the issuance of additional senior notes in 2014. In 2013, interest expense, net of amounts capitalized decreased $4.2 million, or 7.0%, compared to the prior year primarily due to lower interest rates on pollution control bonds, senior notes, and customer deposits.

Income Taxes

Income taxes increased $8.4 million, or 10.5%, in 2014 compared to the prior year primarily due to higher pre-tax earnings. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

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 wholesale electricity sales, 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 "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 Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, the rate of economic growth or decline in the Company's service territory, and the successful remarketing of wholesale capacity as current contracts expire. Changes in regional and global economic conditions may impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

The Company's wholesale business consists of two types of agreements. The first type, referred to as requirements service, provides that the Company serves the customer's capacity and energy requirements from other Company resources. The second type, referred to as a unit sale, is a wholesale customer purchase from a dedicated generating plant unit where a portion of that unit is reserved for the customer. These agreements are associated with the Company's co-ownership of a unit with Georgia Power at Plant Scherer and consist of both capacity and energy sales. Capacity revenues represent the majority of the Company's wholesale earnings. The Company currently has long-term sales agreements for 100% of the Company's ownership of that unit for 2015 and 41% for the next five years. These capacity revenues represented 82% of total wholesale capacity revenues for 2014. The Company is actively pursuing replacement wholesale contracts but the expiration of current contracts could have a material negative impact on the Company's earnings. In the event some portion of the Company's ownership in Plant Scherer is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the power pool or into the wholesale market.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be recovered in retail rates or through long-term wholesale agreements on a timely basis or through market-based contracts. The State of Florida has statutory provisions that allow 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 Company's current long-term wholesale agreements contain provisions that permit charging the customer with 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. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Further, higher costs that are recovered through regulated rates or long-term wholesale agreements could contribute to reduced demand for electricity as well as impact the cost competitiveness of wholesale capacity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" and "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Subsequent to December 31, 2014, the Company announced plans to retire its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) by March 31, 2016. The plant will continue to operate and produce electricity with its other generating units on site. The cost to comply with environmental regulations imposed by the EPA led to the decision to close these units. The retirement of these units is not expected to have a material impact on the Company's financial statements. The Company expects to recover through its rates the remaining book value of the retired units and certain costs associated with the retirements; however, recovery will be considered by the Florida PSC in future rate proceedings. The net book value of these units at December 31, 2014 was approximately $80 million.

The Company has also determined it is not economical to add the environmental controls at Plant Scholz necessary to comply with the Mercury and Air Toxics Standards (MATS) rule and that coal-fired generation at Plant Scholz (92 MWs) will cease by April 2015. The plant is scheduled to be fully depreciated by April 2015.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. See Note 3 to the financial statements under "Environmental Matters – New Source Review Actions" for additional information. 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; the Endangered Species Act; and related federal and state regulations. 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 2014, the Company had invested approximately $1.8 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $227 million, $143 million, and $70 million for 2014, 2013, and 2012, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $204 million from 2015 through 2017, with annual totals of approximately $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters 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. Since 1990, the Company has spent approximately $1.4 billion in reducing and monitoring emissions pursuant to the Clean Air

Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the MATS rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. Compliance for existing sources is required by April 16, 2015, up to April 16, 2016 for affected units for which extensions have been granted. On November 25, 2014, the U.S. Supreme Court granted a petition for review of the final MATS rule.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard. On December 17, 2014, the EPA published a proposed rule to further reduce the current eight-hour ozone standard. The EPA is required by federal court order to complete this rulemaking by October 1, 2015. Finalization of a lower eight-hour ozone standard could result in the designation of new ozone nonattainment areas within the Company's service territory.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard on December 18, 2014, and no new nonattainment areas were designated within the Company's service territory. The EPA has, however, deferred designation decisions for certain areas in Florida, so future nonattainment designations in these areas are possible.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Company's service territory have been designated as nonattainment under this rule. However, the EPA has announced plans to make additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I beginning in 2015 and Phase II beginning in 2017. In 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety, but on April 29, 2014, the U.S. Supreme Court overturned that decision and remanded the case back to the U.S. Court of Appeals for the District of Columbia Circuit for further proceedings. The U.S. Court of Appeals for the District of Columbia Circuit granted the EPA's motion to lift the stay of the rule, and the first phase of CSAPR took effect on January 1, 2015.

The EPA finalized the Clean Air Visibility Rule (CAVR) in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units), during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

In February 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposed to supplement the 2013 proposed rule on September 17, 2014, making it more stringent. The EPA has entered into a settlement agreement requiring it to finalize the proposed rule by May 22, 2015. The proposed rule would require states subject to the rule (including Florida, Georgia, and Mississippi) to revise their SSM provisions within 18 months after issuance of the final rule.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CSAPR, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective on October 14, 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

In June 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing revised technology-based limits for certain wastestreams from steam electric power plants and best management practices for CCR surface impoundments. The EPA has entered into a consent decree requiring it to finalize revisions to the steam electric effluent guidelines by September 30, 2015. The ultimate impact of the rule will also depend on the specific technology requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time.

On April 21, 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to revise the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs, which would significantly expand the scope of federal jurisdiction under the CWA. In addition, the rule as proposed could have significant impacts on economic development projects which could affect customer demand growth. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and the outcome of any legal challenges and cannot be determined at this time. If finalized as proposed, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's National Pollutant Discharge Elimination System permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

These proposed and final water quality regulations could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

Coal Combustion Residuals

The Company currently manages CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at three electric generating plants in Florida and is part owner of units at generating plants located in Mississippi and Georgia operated by the respective unit's co-owner. In addition to on-site storage, the Company sells a portion of its CCR to third parties for beneficial reuse. Individual states regulate CCR and the States of Florida, Georgia, and Mississippi each have their own regulatory requirements. The Company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not mandate closure of CCR Units, but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the mandated closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded asset retirement obligations (ARO) associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Environmental Remediation

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 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 impacted sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. 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

In 2014, the EPA published three sets of proposed standards that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. On January 8, 2014, the EPA published proposed standards for new units, and, on June 18, 2014, the EPA published proposed standards governing existing units, known as the Clean Power Plan, and separate standards governing CO_2 emissions from modified and reconstructed units. The EPA's proposed Clean Power Plan establishes guidelines for states to develop plans to address CO_2 emissions from existing fossil fuel-fired electric generating units. The EPA's proposed guidelines establish state-specific interim and final CO_2 emission rate goals to be achieved between 2020 and 2029 and in 2030 and thereafter. The proposed guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through market-based contracts.

The Southern Company system filed comments on the EPA's proposed Clean Power Plan on December 1, 2014. These comments addressed legal and technical issues in addition to providing a preliminary estimated cost of complying with the proposed guidelines utilizing one of the EPA's compliance scenarios. Costs associated with this proposal could be significant to the utility industry and the Southern Company system. However, the ultimate financial and operational impact of the proposed Clean Power Plan on the Southern Company system cannot be determined at this time and will depend upon numerous known and unknown factors. Some of the unknown factors include: the structure, timing, and content of the EPA's final guidelines; individual state implementation of these guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

Over the past several years, the U.S. Congress has also considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2013 greenhouse gas emissions were approximately 8 million metric tons of CO_2 equivalent. The preliminary estimate of the Company's 2014 greenhouse gas emissions on the same basis is approximately 10 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. The Company recognized an $8.4 million reduction in depreciation expense in 2014.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.

Income Tax Matters

Bonus Depreciation

On December 19, 2014, the Tax Increase Prevention Act of 2014 (TIPA) was signed into law. The TIPA retroactively extended several tax credits through 2014 and extended 50% bonus depreciation for property placed in service in 2014 (and for certain long-term production-period projects to be placed in service in 2015). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows and, combined with bonus depreciation allowed in 2014 under the American Taxpayer Relief Act of 2012, resulted in approximately $25 million of positive cash flows for the 2014 tax year. The estimated cash flow benefit of bonus depreciation related to TIPA is expected to be approximately $65 million to $70 million for the 2015 tax year.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. 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 or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. 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 Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require 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 the accounting standards 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, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition 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 any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. 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 subject it to environmental, litigation, 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, in accordance with GAAP, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. 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 position, results of operations, or cash flows.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high-quality fixed income securities with maturities that correspond to expected benefit payments.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively. The adoption of new mortality tables will increase net periodic costs related to the Company's pension plans and other postretirement benefit plans in 2015 by $3.9 million and $0.1 million, respectively.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $1.6 million or less change in total annual benefit expense and a $22.0 million or less change in projected obligations.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2014. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2015 through 2017, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period are primarily to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances and through equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 2014 as compared to December 31, 2013. In December 2014, the Company voluntarily contributed $30.0 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $343.1 million in 2014, an increase of $13.4 million from 2013, primarily due to changes in cash flows related to clause recovery and a decrease in fossil fuel stock. This increase was partially offset by decreases in cash flows associated with pension, post-retirement and other employee benefits, and deferred income taxes.

In 2013, net cash provided from operating activities totaled $329.7 million, a decrease of $89.5 million from 2012, primarily due to decreases in deferred income taxes related to bonus depreciation and lower recovery of fuel costs which moved from an over recovered to an under recovered position. These decreases were partially offset by increases in cash flow related to reductions in fossil fuel stock.

Net cash used for investing activities totaled $357.7 million, $306.6 million, and $348.6 million for 2014, 2013, and 2012, respectively. The changes in cash used for investing activities were primarily due to gross property additions to utility plant of $360.9 million, $304.8 million, and $325.2 million for 2014, 2013, and 2012, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

Net cash provided from financing activities totaled $31.5 million for 2014. Net cash used for financing activities totaled $33.6 million and $55.8 million for 2013 and 2012, respectively. The $65.1 million increase in cash from financing activities in 2014 was primarily due to the issuance of long-term debt and common stock, partially offset by the payment of common stock dividends, the redemption of long-term debt and a decrease to notes payable. The decreases of cash used in 2013 and 2012 were primarily for the payment of common stock dividends and redemptions of long-term debt, partially offset by issuances of stock to Southern Company and issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2014 included increases of $231.3 million in property, plant, and equipment, primarily due to additions in generation, transmission, and distribution facilities, $211.4 million in long-term debt, $75.6 million in other regulatory assets, deferred, related to pension and other postretirement benefits, $55.7 million in other regulatory assets primarily related to an increase in contract hedges, $50.0 million in common stock issued to Southern Company, and $44.4 million in employee benefit obligations as a result of changes in the actuarial assumptions. Decreases included $75.0 million in securities due within one year.

The Company's ratio of common equity to total capitalization, including short-term debt, was 44.6% in 2014 and 44.9% in 2013. See Note 6 to the financial statements for additional information.

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, short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

Security issuances are subject to annual 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 in the Southern Company system.

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. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs, including its commercial paper program which is supported by bank credit facilities.

At December 31, 2014, the Company had approximately $38.6 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2014 were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
				(in millions)				
$80	$ 165	$30	$275	$275	$50	$—	$50	$30

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings. Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration.

Most of the unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014 was approximately $69.3 million. At December 31, 2014, the Company had $78.0 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period			Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate		Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)			*(in millions)*		*(in millions)*
December 31, 2014:						
Commercial paper	**$ 110**	**0.3%**		**$ 85**	**0.2%**	**$145**
December 31, 2013:						
Commercial paper	$ 136	0.2%		$ 92	0.2%	$173
Short-term bank debt	—	N/A		11	1.2%	125
Total	$ 136	0.2%		$ 103	0.3%	
December 31, 2012:						
Commercial paper	$ 124	0.3%		$ 69	0.3%	$124

(a) Average and maximum amounts are based upon daily balances during the year.

The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, lines of credit, and cash.

Financing Activities

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50.0 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program, and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm recovery, 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.

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- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, and energy price risk management. The maximum potential collateral requirements under these contracts at December 31, 2014 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 74
Below BBB- and/or Baa3	447

Included in these amounts are certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have 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, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management 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 testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $69.3 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2015 was .02%. 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 $0.7 million at January 1, 2015. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Company had no material change in market risk exposure for the year ended December 31, 2014 when compared to the year ended December 31, 2013.

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

	2014 Changes	2013 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (10)**	$ (23)
Contracts realized or settled	**(3)**	13
Current period changes[(a)]	**(59)**	—
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (72)**	$ (10)

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

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

	2014	2013
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**85**	87
Commodity – Natural gas options	**—**	2
Total hedge volume	**85**	89

The weighted average swap contract cost above market prices was approximately $0.80 per mmBtu as of December 31, 2014 and $0.12 per mmBtu as of December 31, 2013. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2014 and 2013, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2014 were as follows:

	Fair Value Measurements December 31, 2014			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	(72)	(37)	(33)	(2)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (72)	$ (37)	$ (33)	$ (2)

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, 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 Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $263 million for 2015, $186 million for 2016, and $168 million for 2017. Capital expenditures to comply with environmental statutes and regulations included in these amounts are estimated to be $127 million, $39 million, and $38 million for 2015, 2016, and 2017, respectively. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's proposed rules that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Global Climate Issues" for additional information.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts;

changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; 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 FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

Contractual Obligations

	2015	2016-2017	2018-2019	After 2019	Total
			(in thousands)		
Long-term debt[a] –					
Principal	$ —	$ 195,000	$ —	$1,183,955	$1,378,955
Interest	57,546	109,262	93,402	853,213	1,113,423
Financial derivative obligations[b]	36,934	32,938	2,563	—	72,435
Preference stock dividends[c]	9,003	18,006	18,006	—	45,015
Operating leases[d]	15,239	16,624	—	—	31,863
Unrecognized tax benefits[e]	46	—	—	—	46
Purchase commitments –					
Capital[f]	262,814	326,536	—	—	589,350
Fuel[g]	276,437	349,155	255,854	145,535	1,026,981
Purchased power[h]	92,395	183,929	182,929	315,331	774,584
Other[i]	16,498	20,616	15,820	43,145	96,079
Pension and other postretirement benefit plans[j]	4,716	10,061	—	—	14,777
Total	$771,628	$1,262,127	$568,574	$2,541,179	$5,143,508

(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, 2015, 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 10 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) Excludes a PPA accounted for as a lease and is included in purchased power.

(e) See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information.

(f) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in Other. At December 31, 2014, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(g) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2014.

(h) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity clause. See Notes 3 and 7 to the financial statements for additional information.

(i) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

(j) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years. Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2014 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, access to sources of capital, projections for the qualified pension plan and postretirement benefit plan contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impact of the TIPA, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and 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 changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws including regulation of water, CCR, and emissions of sulfur, nitrogen, CO_2, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in 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 pending EPA civil action against the Company and IRS and state tax audits;
- 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 recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards;
- investment performance of the Company's employee and retiree 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 other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- 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 and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;

- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- 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.

[This page intentionally left blank]

STATEMENTS OF INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Revenues:			
Retail revenues	**$ 1,266,540**	$ 1,170,000	$ 1,144,471
Wholesale revenues, non-affiliates	**129,151**	109,386	106,881
Wholesale revenues, affiliates	**130,107**	99,577	123,636
Other revenues	**64,684**	61,338	64,774
Total operating revenues	**1,590,482**	1,440,301	1,439,762
Operating Expenses:			
Fuel	**604,641**	532,791	544,936
Purchased power, non-affiliates	**81,993**	52,443	51,421
Purchased power, affiliates	**25,246**	32,835	22,665
Other operations and maintenance	**341,214**	309,865	314,195
Depreciation and amortization	**145,026**	149,009	141,038
Taxes other than income taxes	**111,147**	98,355	97,313
Total operating expenses	**1,309,267**	1,175,298	1,171,568
Operating Income	**281,215**	265,003	268,194
Other Income and (Expense):			
Allowance for equity funds used during construction	**12,021**	6,448	5,221
Interest income	**90**	369	1,408
Interest expense, net of amounts capitalized	**(53,234)**	(56,025)	(60,250)
Other income (expense), net	**(2,851)**	(3,994)	(3,227)
Total other income and (expense)	**(43,974)**	(53,202)	(56,848)
Earnings Before Income Taxes	**237,241**	211,801	211,346
Income taxes	**88,062**	79,668	79,211
Net Income	**149,179**	132,133	132,135
Dividends on Preference Stock	**9,003**	7,704	6,203
Net Income After Dividends on Preference Stock	**$ 140,176**	$ 124,429	$ 125,932

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

		2014		2013		2012
				(in thousands)		
Net Income	**$**	**149,179**	$	132,133	$	132,135
Other comprehensive income (loss):						
Qualifying hedges:						
Reclassification adjustment for amounts included in net income, net of tax of $234, $297, and $360, respectively		**372**		472		573
Total other comprehensive income (loss)		**372**		472		573
Comprehensive Income	**$**	**149,551**	$	132,605	$	132,708

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	2014	2013	2012
		(in thousands)	
Operating Activities:			
Net income	**$ 149,179**	$ 132,133	$ 132,135
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**152,670**	155,798	147,723
Deferred income taxes	**65,330**	77,069	174,305
Allowance for equity funds used during construction	**(12,021)**	(6,448)	(5,221)
Pension, postretirement, and other employee benefits	**(23,305)**	11,422	(8,109)
Stock based compensation expense	**1,928**	1,749	1,647
Other, net	**(1,233)**	5,865	4,518
Changes in certain current assets and liabilities —			
-Receivables	**(17,178)**	(49,051)	8,713
-Fossil fuel stock	**33,603**	19,468	(6,144)
-Materials and supplies	**(721)**	(1,570)	(3,035)
-Prepaid income taxes	**(19,179)**	15,526	355
-Other current assets	**(883)**	682	417
-Accounts payable	**8,279**	(6,964)	(5,195)
-Accrued taxes	**(1,924)**	(4,759)	(4,705)
-Accrued compensation	**11,237**	(3,309)	481
-Over recovered regulatory clause revenues	**—**	(17,092)	(10,858)
-Other current liabilities	**(2,704)**	(782)	(7,837)
Net cash provided from operating activities	**343,078**	329,737	419,190
Investing Activities:			
Property additions	**(348,305)**	(292,914)	(313,257)
Cost of removal net of salvage	**(12,932)**	(13,827)	(28,993)
Construction payables	**11,574**	6,796	1,161
Payments pursuant to long-term service agreements	**(8,012)**	(7,109)	(8,119)
Other investing activities	**(19)**	496	656
Net cash used for investing activities	**(357,694)**	(306,558)	(348,552)
Financing Activities:			
Increase (decrease) in notes payable, net	**(25,900)**	12,108	16,075
Proceeds —			
Common stock issued to parent	**50,000**	40,000	40,000
Capital contributions from parent company	**4,037**	2,987	2,106
Preference stock	**—**	50,000	—
Pollution control revenue bonds	**42,075**	63,000	13,000
Senior notes	**200,000**	90,000	100,000
Redemptions —			
Pollution control revenue bonds	**(29,075)**	(76,000)	(13,000)
Senior notes	**(75,000)**	(90,000)	(91,363)
Payment of preference stock dividends	**(9,003)**	(7,004)	(6,203)
Payment of common stock dividends	**(123,200)**	(115,400)	(115,800)
Other financing activities	**(2,457)**	(3,284)	(614)
Net cash provided from (used for) financing activities	**31,477**	(33,593)	(55,799)
Net Change in Cash and Cash Equivalents	**16,861**	(10,414)	14,839
Cash and Cash Equivalents at Beginning of Year	**21,753**	32,167	17,328
Cash and Cash Equivalents at End of Year	**$ 38,614**	$ 21,753	$ 32,167
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $5,373, $3,421 and $2,500 capitalized, respectively)	**$ 48,030**	$ 53,401	$ 58,255
Income taxes (net of refunds)	**44,125**	(10,727)	(96,639)
Noncash transactions — accrued property additions at year-end	**41,526**	31,546	27,369

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

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Assets	**2014**	2013
		(in thousands)
Current Assets:		
Cash and cash equivalents	**$ 38,614**	$ 21,753
Receivables —		
Customer accounts receivable	**73,000**	64,884
Unbilled revenues	**58,268**	57,282
Under recovered regulatory clause revenues	**57,153**	48,282
Other accounts and notes receivable	**8,145**	8,620
Affiliated companies	**9,867**	8,259
Accumulated provision for uncollectible accounts	**(2,087)**	(1,131)
Fossil fuel stock, at average cost	**101,447**	135,050
Materials and supplies, at average cost	**55,656**	54,935
Other regulatory assets, current	**74,242**	18,536
Prepaid expenses	**39,673**	33,186
Other current assets	**1,711**	6,120
Total current assets	**515,689**	455,776
Property, Plant, and Equipment:		
In service	**4,494,953**	4,363,664
Less accumulated provision for depreciation	**1,295,714**	1,211,336
Plant in service, net of depreciation	**3,199,239**	3,152,328
Construction work in progress	**465,033**	280,626
Total property, plant, and equipment	**3,664,272**	3,432,954
Other Property and Investments	**15,148**	15,314
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**55,931**	50,597
Prepaid pension costs	**—**	11,533
Other regulatory assets, deferred	**416,028**	340,415
Other deferred charges and assets	**41,191**	30,982
Total deferred charges and other assets	**513,150**	433,527
Total Assets	**$ 4,708,259**	$ 4,337,571

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

BALANCE SHEETS
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

Liabilities and Stockholder's Equity	**2014**	2013
		(in thousands)
Current Liabilities:		
Securities due within one year	**$ —**	$ 75,000
Notes payable	**109,977**	135,878
Accounts payable —		
Affiliated	**87,397**	76,897
Other	**55,848**	47,038
Customer deposits	**35,094**	34,433
Accrued taxes —		
Accrued income taxes	**46**	45
Other accrued taxes	**9,201**	7,486
Accrued interest	**10,686**	10,272
Accrued compensation	**22,894**	11,657
Deferred capacity expense, current	**21,988**	—
Other regulatory liabilities, current	**566**	13,408
Liabilities from risk management activities	**36,934**	6,470
Other current liabilities	**22,386**	22,972
Total current liabilities	**413,017**	441,556
Long-Term Debt (See accompanying statements)	**1,369,594**	1,158,163
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**799,723**	734,355
Accumulated deferred investment tax credits	**2,783**	4,055
Employee benefit obligations	**120,752**	76,338
Deferred capacity expense	**163,077**	180,149
Other cost of removal obligations	**234,587**	228,148
Other regulatory liabilities, deferred	**48,556**	56,051
Other deferred credits and liabilities	**100,076**	77,126
Total deferred credits and other liabilities	**1,469,554**	1,356,222
Total Liabilities	**3,252,165**	2,955,941
Preference Stock (See accompanying statements)	**146,504**	146,504
Common Stockholder's Equity (See accompanying statements)	**1,309,590**	1,235,126
Total Liabilities and Stockholder's Equity	**$ 4,708,259**	$ 4,337,571
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2014 and 2013
Gulf Power Company 2014 Annual Report

	2014	2013	**2014**	2013
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
4.90% due 2014	—	75,000		
5.30% due 2016	**110,000**	110,000		
5.90% due 2017	**85,000**	85,000		
3.10% to 5.75% due 2020-2051	**875,000**	675,000		
Total long-term notes payable	**1,070,000**	945,000		
Other long-term debt —				
Pollution control revenue bonds —				
0.55% to 6.00% due 2022-2049	**239,625**	226,625		
Variable rates (0.02% to 0.04% at 1/1/15) due 2022-2039	**69,330**	69,330		
Total other long-term debt	**308,955**	295,955		
Unamortized debt discount	**(9,361)**	(7,792)		
Total long-term debt (annual interest requirement — $57.5 million)	**1,369,594**	1,233,163		
Less amount due within one year	—	75,000		
Long-term debt excluding amount due within one year	**1,369,594**	1,158,163	**48.5%**	45.6%
Preferred and Preference Stock:				
Authorized — 20,000,000 shares — preferred stock				
— 10,000,000 shares — preference stock				
Outstanding — $100 par or stated value				
— 6% preference stock — 550,000 shares (non-cumulative)	**53,886**	53,886		
— 6.45% preference stock — 450,000 shares (non-cumulative)	**44,112**	44,112		
— 5.60% preference stock — 500,000 shares (non-cumulative)	**48,506**	48,506		
Total preference stock (annual dividend requirement — $9.0 million)	**146,504**	146,504	**5.2**	5.8
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 2014: 5,442,717 shares				
— 2013: 4,942,717 shares	**483,060**	433,060		
Paid-in capital	**559,797**	552,681		
Retained earnings	**267,470**	250,494		
Accumulated other comprehensive loss	**(737)**	(1,109)		
Total common stockholder's equity	**1,309,590**	1,235,126	**46.3**	48.6
Total Capitalization	**$ 2,825,688**	$ 2,539,793	**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, 2014, 2013, and 2012
Gulf Power Company 2014 Annual Report

	Number of Common Shares Issued	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
				(in thousands)		
Balance at December 31, 2011	4,143	$ 353,060	$ 542,709	$ 231,333	$ (2,154)	$ 1,124,948
Net income after dividends on preference stock	—	—	—	125,932	—	125,932
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	5,089	—	—	5,089
Other comprehensive income (loss)	—	—	—	—	573	573
Cash dividends on common stock	—	—	—	(115,800)	—	(115,800)
Balance at December 31, 2012	4,543	393,060	547,798	241,465	(1,581)	1,180,742
Net income after dividends on preference stock	—	—	—	124,429	—	124,429
Issuance of common stock	400	40,000	—	—	—	40,000
Capital contributions from parent company	—	—	4,883	—	—	4,883
Other comprehensive income (loss)	—	—	—	—	472	472
Cash dividends on common stock	—	—	—	(115,400)	—	(115,400)
Balance at December 31, 2013	**4,943**	**433,060**	**552,681**	**250,494**	**(1,109)**	**1,235,126**
Net income after dividends on preference stock	**—**	**—**	**—**	**140,176**	**—**	**140,176**
Issuance of common stock	**500**	**50,000**	**—**	**—**	**—**	**50,000**
Capital contributions from parent company	**—**	**—**	**7,116**	**—**	**—**	**7,116**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**372**	**372**
Cash dividends on common stock	**—**	**—**	**—**	**(123,200)**	**—**	**(123,200)**
Balance at December 31, 2014	**5,443**	**$ 483,060**	**$ 559,797**	**$ 267,470**	**$ (737)**	**$ 1,309,590**

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

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, as well as Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, 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 for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Florida PSC. The Company follows GAAP in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

Recently Issued Accounting Standards

On May 28, 2014, the Financial Accounting Standards Board issued ASC 606, Revenue from Contracts with Customers. ASC 606 revises the accounting for revenue recognition and is effective for fiscal years beginning after December 15, 2016. The Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

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, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $79.6 million, $78.4 million, and $95.9 million during 2014, 2013, and 2012, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.7 million, $10.2 million, and $6.9 million and Mississippi Power $30.5 million, $16.5 million, and $21.1 million in 2014, 2013, and 2012, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a PPA with Southern Power for approximately 292 MWs annually from June 2009 through May 2014. Purchased power expenses associated with the PPA were $1.8 million, $14.2 million, and $14.7 million in 2014, 2013, and 2012, respectively, and fuel costs associated with the PPA were $1.7 million, $0.8 million, and $2.6 million in 2014, 2013, and 2012, respectively. These costs were approved for recovery by the Florida PSC through the Company's fuel and purchased power capacity cost recovery clauses. See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company had an agreement with Georgia Power under the transmission facility cost allocation tariff for delivery of power from the Company's resources in the state of Georgia. The Company reimbursed Georgia Power $1.0 million in 2014 and $2.4 million in each of the years 2013 and 2012 for its share of related expenses.

The Company has an agreement with Alabama Power under which Alabama Power has made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA, which was entered into in 2009 for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. Revenue requirement obligations to Alabama Power for these upgrades are estimated to be $132.0 million for the entire project. These costs began in July 2012 and will continue through 2023.

The Company reimbursed Alabama Power $11.9 million, $7.9 million, and $3.0 million in 2014, 2013, and 2012, respectively, for the revenue requirements. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2014, 2013, or 2012.

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 and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board in accounting for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2014	2013	Note
	(in thousands)		
Deferred income tax charges	**$ 53,234**	$ 47,573	(a)
Deferred income tax charges — Medicare subsidy	**3,024**	3,351	(b)
Asset retirement obligations	**(5,087)**	(6,089)	(a,j)
Other cost of removal obligations	**(242,997)**	(228,148)	(a)
Regulatory asset, offset to other cost of removal	**8,410**	—	(m)
Deferred income tax credits	**(3,872)**	(5,238)	(a)
Loss on reacquired debt	**15,991**	16,565	(c)
Vacation pay	**10,006**	9,521	(d,j)
Under recovered regulatory clause revenues	**52,619**	45,191	(e)
Property damage reserve	**(35,111)**	(35,380)	(f)
Fuel-hedging (realized and unrealized) losses	**73,474**	17,043	(g,j)
Fuel-hedging (realized and unrealized) gains	**(112)**	(6,962)	(g,j)
PPA charges	**185,065**	180,149	(j,k)
Other regulatory assets	**9,753**	12,772	(l)
Environmental remediation	**48,271**	50,384	(h,j)
Other regulatory liabilities	**(649)**	(8,804)	(f,j)
Retiree benefit plans, net	**147,625**	68,296	(i,j)
Total regulatory assets (liabilities), net	**$ 319,644**	$ 160,224	

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(b) Recovered and amortized over periods not exceeding 14 years.

(c) 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 40 years.

(d) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(e) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

(f) Recorded and recovered or amortized as approved by the Florida PSC.

(g) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(h) Recovered through the environmental cost recovery clause when the remediation is performed.

(i) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(j) Not earning a return as offset in rate base by a corresponding asset or liability.

(k) Recovered over the life of the PPA for periods up to nine years.

(l) Comprised primarily of net book value of retired meters, deferred rate case expenses, and generation site evaluation costs. These costs are recorded and recovered or amortized as approved by the Florida PSC, generally over periods not exceeding eight years, or deferred pursuant to Florida statute while the Company continues to evaluate certain potential new generating projects.

(m) Recorded as authorized by the Florida PSC in a settlement agreement approved in December 2013. See Note 3 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI 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" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. 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 Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable 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 amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida 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. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. 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.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any 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 cost of equity funds used during construction.

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

	2014	2013
	(in thousands)	
Generation	**$ 2,637,817**	$ 2,607,166
Transmission	**515,754**	473,378
Distribution	**1,156,872**	1,117,024
General	**182,734**	164,065
Plant acquisition adjustment	**1,776**	2,031
Total plant in service	**$ 4,494,953**	$ 4,363,664

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 other operations and maintenance expenses as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.6% in 2014, 2013, and 2012. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. 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 are 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. As authorized by the Florida PSC in the settlement agreement approved in December 2013 (Settlement Agreement), the Company is allowed to reduce depreciation expense and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the ultimate costs for an asset's future retirement and are 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. The Company has received an order 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 are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, 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 U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. 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 in accordance with accounting standards related to asset retirement and environmental obligations 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 AROs included in the balance sheets are as follows:

	2014	2013
	(in thousands)	
Balance at beginning of year	**$ 16,184**	$ 16,055
Liabilities incurred	**—**	518
Liabilities settled	**(32)**	(1,913)
Accretion	**718**	751
Cash flow revisions	**(159)**	773
Balance at end of year	**$ 16,711**	$ 16,184

The 2014 cash flow revisions are associated with asbestos and ash ponds at the Company's steam generation facilities. The 2013 cash flow revisions are associated with asbestos and an unloading dock at its generation facilities.

On December 19, 2014, the EPA issued the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), but has not yet published it in the Federal Register. The CCR Rule will regulate the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in landfills and surface impoundments at active generating power plants. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the Company's ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. The cost and timing of potential ash pond closure and ongoing monitoring activities that may be required in connection with the CCR Rule is also uncertain; however, the Company has developed a preliminary nominal dollar estimate of costs associated with closure and groundwater monitoring of ash ponds in place of approximately $62 million and ongoing post-closure care of approximately $11 million. The Company has previously recorded AROs associated with ash ponds of $6 million, or $11 million on a nominal dollar basis, based on existing state requirements. During 2015, the Company will record AROs for any incremental estimated closure costs resulting from acceleration in the timing of any currently planned closures and for differences between existing state requirements and the requirements of the CCR Rule. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates.

Allowance for Funds Used During Construction

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, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for 2014, 6.26% for 2013, and 6.72% for 2012. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 10.93%, 6.87%, and 5.36% for 2014, 2013, and 2012, 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.

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 costs of such damage are 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 $48.0 million and $55.0 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 $3.5 million in each of 2014, 2013, and 2012. As of December 31, 2014 and 2013, the balance in the Company's property damage reserve totaled approximately $35.7 million and $35.4 million, respectively, which is included in deferred liabilities in the balance sheets.

When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. In December 2013, the Florida PSC approved the Settlement Agreement that, among other things, provides for recovery of costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00/1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if the Company incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013. See Note 3 herein under "Retail Regulatory Matters – Retail Base Rate Case" for additional details of the Settlement Agreement.

Injuries and Damages Reserve

The Company is subject to claims and lawsuits 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 $2.0 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 $4.0 million and $3.6 million at December 31, 2014 and 2013, respectively. For 2014, $1.6 million and $2.4 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. For 2013, $1.6 million and $2.0 million are included in current liabilities and deferred credits and other liabilities in the balance sheets, respectively. There were no liabilities in excess of the reserve balance at December 31, 2014 or 2013.

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, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average cost of oil, natural gas, coal, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

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 (included in “Other” or shown separately as “Risk Management Activities”) and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company’s bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the “normal” scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI 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 that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 10 for additional information regarding derivatives.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2014.

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.

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 reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In December 2014, the Company voluntarily contributed $30 million to the qualified pension plan. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2015. 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 its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2015, no other postretirement trust contributions are expected.

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 were calculated in 2011 for the 2012 plan year using discount rates for the pension plans and the other postretirement benefit plans of 4.98% and 4.88%, respectively, and an annual salary increase of 3.84%.

	2014	2013	2012
Discount rate:			
Pension plans	**4.18%**	5.02%	4.27%
Other postretirement benefit plans	**4.04**	4.86	4.06
Annual salary increase	**3.59**	3.59	3.59
Long-term return on plan assets:			
Pension plans	**8.20**	8.20	8.20
Other postretirement benefit plans	**8.08**	8.04	8.02

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

For purposes of its December 31, 2014 measurement date, the Company adopted new mortality tables for its pension plans and retiree life and medical plans, which reflect increased life expectancies in the U.S. The adoption of new mortality tables increased the projected benefit obligations for the Company's pension plans and other postretirement benefit plans by approximately $29.6 million and $2.6 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2014 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	9.00%	4.50%	2024
Post-65 medical	6.00	4.50	2024
Post-65 prescription	6.75	4.50	2024

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2014 as follows:

	1 Percent Increase	1 Percent Decrease
	(in thousands)	
Benefit obligation	$ 3,934	$ (3,334)
Service and interest costs	157	(133)

Pension Plans

The total accumulated benefit obligation for the pension plans was $438 million at December 31, 2014 and $353 million at December 31, 2013. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 395,328**	$ 413,501
Service cost	**10,181**	11,128
Interest cost	**19,433**	17,321
Benefits paid	**(15,635)**	(14,831)
Actuarial (gain) loss	**81,254**	(31,791)
Balance at end of year	**490,561**	395,328
Change in plan assets		
Fair value of plan assets at beginning of year	**385,639**	350,260
Actual return on plan assets	**33,512**	49,076
Employer contributions	**31,251**	1,134
Benefits paid	**(15,635)**	(14,831)
Fair value of plan assets at end of year	**434,767**	385,639
Accrued liability	**$ (55,794)**	$ (9,689)

At December 31, 2014, the projected benefit obligations for the qualified and non-qualified pension plans were $464 million and $26 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's pension plans consist of the following:

	2014	2013
	(in thousands)	
Prepaid pension costs	**$ —**	$ 11,533
Other regulatory assets, deferred	**145,815**	75,280
Current liabilities, other	**(1,307)**	(1,183)
Employee benefit obligations	**(54,487)**	(20,039)

Presented below are the amounts included in regulatory assets at December 31, 2014 and 2013 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2015.

	2014	2013	**Estimated Amortization in 2015**
		(in thousands)	
Prior service cost	**$ 3,286**	$ 4,401	**$ 1,115**
Net (gain) loss	**142,529**	70,879	**9,281**
Regulatory assets	**$ 145,815**	$ 75,280	

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Regulatory assets:		
Beginning balance	**$ 75,280**	$ 139,261
Net (gain) loss	**76,209**	(54,432)
Reclassification adjustments:		
Amortization of prior service costs	**(1,115)**	(1,164)
Amortization of net gain (loss)	**(4,559)**	(8,385)
Total reclassification adjustments	**(5,674)**	(9,549)
Total change	**70,535**	(63,981)
Ending balance	**$ 145,815**	$ 75,280

Components of net periodic pension cost were as follows:

	2014	2013	2012
		(in thousands)	
Service cost	**$ 10,181**	$ 11,128	$ 9,101
Interest cost	**19,433**	17,321	17,199
Expected return on plan assets	**(28,468)**	(26,435)	(25,932)
Recognized net (gain) loss	**4,559**	8,385	3,913
Net amortization	**1,115**	1,164	1,262
Net periodic pension cost	**$ 6,820**	$ 11,563	$ 5,543

Net periodic pension cost 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, 2014, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2015	$ 22,002
2016	18,683
2017	19,950
2018	21,019
2019	22,229
2020 to 2024	129,877

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 68,579**	$ 75,395
Service cost	**1,163**	1,355
Interest cost	**3,235**	2,982
Benefits paid	**(4,061)**	(3,583)
Actuarial (gain) loss	**11,317**	(7,900)
Plan amendment	**(2,089)**	—
Retiree drug subsidy	**357**	330
Balance at end of year	**78,501**	68,579
Change in plan assets		
Fair value of plan assets at beginning of year	**17,474**	16,227
Actual return on plan assets	**1,578**	2,119
Employer contributions	**2,846**	2,381
Benefits paid	**(3,704)**	(3,253)
Fair value of plan assets at end of year	**18,194**	17,474
Accrued liability	**$ (60,307)**	$ (51,105)

Amounts recognized in the balance sheets at December 31, 2014 and 2013 related to the Company's other postretirement benefit plans consist of the following:

	2014	2013
	(in thousands)	
Other regulatory assets, deferred	**$ 6,100**	$ —
Current liabilities, other	**(639)**	(687)
Other regulatory liabilities, deferred	**(4,290)**	(6,984)
Employee benefit obligations	**(59,668)**	(50,418)

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2014 and 2013 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2015.

	2014	2013	Estimated Amortization in 2015
		(in thousands)	
Prior service cost	**$ (2,137)**	$ 138	**$ 25**
Net (gain) loss	**3,947**	(7,122)	**—**
Net regulatory assets (liabilities)	**$ 1,810**	$ (6,984)	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2014 and 2013 are presented in the following table:

	2014	2013
	(in thousands)	
Net regulatory assets (liabilities):		
Beginning balance	**$ (6,984)**	$ 2,169
Net (gain) loss	**11,045**	(8,967)
Change in prior service costs	**(2,089)**	—
Reclassification adjustments:		
Amortization of prior service costs	**(186)**	(186)
Amortization of net gain (loss)	**24**	—
Total reclassification adjustments	**(162)**	(186)
Total change	**8,794**	(9,153)
Ending balance	**$ 1,810**	$ (6,984)

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

	2014	2013	2012
		(in thousands)	
Service cost	**$ 1,163**	$ 1,355	$ 1,167
Interest cost	**3,235**	2,982	3,367
Expected return on plan assets	**(1,306)**	(1,238)	(1,311)
Net amortization	**162**	186	379
Net periodic postretirement benefit cost	**$ 3,254**	$ 3,285	$ 3,602

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in thousands)	
2015	$ 4,694	$ (431)	$ 4,263
2016	4,982	(480)	4,502
2017	5,136	(535)	4,601
2018	5,300	(594)	4,706
2019	5,326	(660)	4,666
2020 to 2024	27,399	(3,430)	23,969

Benefit Plan Assets

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

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2014 and 2013, along with the targeted mix of assets for each plan, is presented below:

	Target	**2014**	2013
Pension plan assets:			
Domestic equity	26%	**30%**	31%
International equity	25	**23**	25
Fixed income	23	**27**	23
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	25%	**29%**	30%
International equity	24	**22**	24
Domestic fixed income	25	**29**	25
Special situations	3	**1**	1
Real estate investments	14	**14**	14
Private equity	9	**5**	6
Total	100%	**100%**	100%

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- ***Domestic equity.*** A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- ***International equity.*** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- ***Fixed income.*** A mix of domestic and international bonds.
- ***Special situations.*** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.
- ***Real estate investments.*** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- ***Private equity.*** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2014 and 2013. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 76,460	$ 31,588	$ —	$ 108,048
International equity*	47,988	44,223	—	92,211
Fixed income:				
U.S. Treasury, government, and agency bonds	—	31,372	—	31,372
Mortgage- and asset-backed securities	—	8,438	—	8,438
Corporate bonds	—	50,931	—	50,931
Pooled funds	—	23,063	—	23,063
Cash equivalents and other	130	29,597	—	29,727
Real estate investments	13,154	—	50,281	63,435
Private equity	—	—	25,573	25,573
Total	$ 137,732	$ 219,212	$ 75,854	$ 432,798
Liabilities:				
Derivatives	$ (87)	$ —	$ —	$ (87)
Total	$ 137,645	$ 219,212	$ 75,854	$ 432,711

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Domestic equity*	$ 63,269	$ 37,037	$ —	$ 100,306
International equity*	48,606	44,941	—	93,547
Fixed income:				
U.S. Treasury, government, and agency bonds	—	26,461	—	26,461
Mortgage- and asset-backed securities	—	6,873	—	6,873
Corporate bonds	—	43,222	—	43,222
Pooled funds	—	20,810	—	20,810
Cash equivalents and other	38	9,851	—	9,889
Real estate investments	11,493	—	44,139	55,632
Private equity	—	—	25,201	25,201
Total	$ 123,406	$ 189,195	$ 69,340	$ 381,941
Liabilities:				
Derivatives	$ —	$ (115)	$ —	$ (115)
Total	$ 123,406	$ 189,080	$ 69,340	$ 381,826

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014		2013	
	Real Estate Investments	**Private Equity**	**Real Estate Investments**	**Private Equity**
		(in thousands)		
Beginning balance	**$ 44,139**	**$ 25,201**	$ 37,039	$ 26,129
Actual return on investments:				
Related to investments held at year end	**4,263**	**2,697**	3,357	376
Related to investments sold during the year	**1,488**	**(727)**	1,310	2,282
Total return on investments	**5,751**	**1,970**	4,667	2,658
Purchases, sales, and settlements	**391**	**(1,598)**	2,433	(3,586)
Ending balance	**$ 50,281**	**$ 25,573**	$ 44,139	$ 25,201

The fair values of other postretirement benefit plan assets as of December 31, 2014 and 2013 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Domestic equity*	$ 3,105	$ 1,283	$ —	$ 4,388
International equity*	1,949	1,798	—	3,747
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,274	—	1,274
Mortgage- and asset-backed securities	—	342	—	342
Corporate bonds	—	2,071	—	2,071
Pooled funds	—	937	—	937
Cash equivalents and other	510	1,203	—	1,713
Real estate investments	534	—	2,042	2,576
Private equity	—	—	1,039	1,039
Total	$ 6,098	$ 8,908	$ 3,081	$ 18,087
Liabilities:				
Derivatives	$ (4)	$ —	$ —	$ (4)
Total	$ 6,094	$ 8,908	$ 3,081	$ 18,083

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2013:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in thousands)			
Assets:				
Domestic equity*	$ 2,778	$ 1,628	$ —	$ 4,406
International equity*	2,136	1,973	—	4,109
Fixed income:				
U.S. Treasury, government, and agency bonds	—	1,161	—	1,161
Mortgage- and asset-backed securities	—	303	—	303
Corporate bonds	—	1,897	—	1,897
Pooled funds	—	1,417	—	1,417
Cash equivalents and other	1	433	—	434
Real estate investments	504	—	1,939	2,443
Private equity	—	—	1,108	1,108
Total	$ 5,419	$ 8,812	$ 3,047	$ 17,278
Liabilities:				
Derivatives	$ —	$ (5)	$ —	$ (5)
Total	$ 5,419	$ 8,807	$ 3,047	$ 17,273

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2014 and 2013 were as follows:

	2014 Real Estate Investments	**2014** Private Equity	2013 Real Estate Investments	2013 Private Equity
	(in thousands)			
Beginning balance	**$ 1,939**	**$ 1,108**	$ 1,667	$ 1,155
Actual return on investments:				
Related to investments held at year end	**27**	**26**	108	16
Related to investments sold during the year	**60**	**(30)**	57	104
Total return on investments	**87**	**(4)**	165	120
Purchases, sales, and settlements	**16**	**(65)**	107	(167)
Ending balance	**$ 2,042**	**$ 1,039**	$ 1,939	$ 1,108

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2014, 2013, and 2012 were $4.2 million, $4.1 million, and $4.0 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, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. 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 ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by the Company. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. These actions were filed concurrently with the issuance of notices of violation of the NSR provisions to the Company with respect to the Company's Plant Crist. The case against Georgia Power (including claims related to a unit co-owned by the Company) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome 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 ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with 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 recognizes a liability for environmental remediation costs only when it determines a loss is probable. At December 31, 2014, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $48.3 million. For 2014, approximately $4.5 million was included in under recovered regulatory clause revenues and other current liabilities, and approximately $43.7 million was included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

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

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Case

In December 2013, the Florida PSC voted to approve the Settlement Agreement among the Company and all of the intervenors to the docketed proceeding with respect to the Company's request to increase retail base rates. Under the terms of the Settlement Agreement, the Company (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and subsequently increased base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2)

continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) will accrue a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until the next base rate adjustment date or January 1, 2017, whichever comes first.

The Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized ROE midpoint and range by 25 basis points in the event the 30-year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six-month period.

The Settlement Agreement also provides that the Company may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in the Company's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. As a result, the Company recognized an $8.4 million reduction in depreciation expense in 2014.

Pursuant to the Settlement Agreement, the Company may not request an increase in its retail base rates to be effective until after June 2017, unless the Company's actual retail ROE falls below the authorized ROE range.

Cost Recovery Clauses

On October 22, 2014, the Florida PSC approved the Company's annual rate clause request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2015. The net effect of the approved changes is an expected $41.2 million increase in annual revenue for 2015. The increased revenues will not have a significant impact on net income since most of the revenues will be offset by expenses.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable 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. The Company filed such notice with the Florida PSC on July 18, 2014, but no adjustment to the factor was requested for 2014.

At December 31, 2014 and 2013, the under recovered fuel balance was approximately $39.9 million and $21.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

Purchased Power Capacity Recovery

The Company has established purchased power capacity recovery cost rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2014 and 2013, the under recovered purchased power capacity balance was approximately $0.3 million and $2.8 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

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 operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. 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.

In 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The Florida PSC's approval of the stipulation also required the Company to file annual updates to the plan and outlined a process for approval of additional elements in the plan when they became committed projects. In the 2010 update filing, the Company identified several elements of the updated plan that the Company had decided to implement. Following the process outlined in the original approved stipulation, these additional projects were approved by the Florida PSC later in 2010. The Florida PSC acknowledged that the costs of the approved projects associated with the Company's Clean Air Interstate Rule and Clean Air Visibility Rule compliance plans are eligible for recovery through the environmental cost recovery clause.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2014 and 2013, the under recovered environmental balance was approximately $9.8 million and $14.4 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

In 2012, the Mississippi PSC approved Mississippi Power's request for a certificate of public convenience and necessity to construct a scrubber on Plant Daniel Units 1 and 2. These units are jointly owned by Mississippi Power and the Company, with 50% ownership each. The estimated total cost of the project is approximately $660 million, with the Company's portion being $330 million, excluding AFUDC, and it is scheduled for completion in December 2015. The Company's portion of the cost is expected to be recovered through the environmental cost recovery clause. On August 28, 2014, the Chancery Court of Harrison County, Mississippi dismissed an appeal by the Sierra Club related to the construction of the scrubber on Plant Daniel Units 1 and 2.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

At December 31, 2014 and 2013, the under recovered energy conservation balance was approximately $2.6 million and $7.0 million, respectively, which is included in under recovered regulatory clause revenues in the balance sheets.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. 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 MWs 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.

At December 31, 2014, the Company's percentage ownership and 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	$ 387,511 [(a)]	$ 285,834
Accumulated depreciation	130,069	177,304
Construction work in progress	2,912	286,343
Company Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $1.8 million.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Florida. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2014	2013	2012
		(in thousands)	
Federal -			
Current	$ 22,771	$ 5,009	$ (92,610)
Deferred	52,602	63,134	161,096
	75,373	68,143	68,486
State -			
Current	(39)	(2,410)	(2,484)
Deferred	12,728	13,935	13,209
	12,689	11,525	10,725
Total	$ 88,062	$ 79,668	$ 79,211

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:

	2014	2013
	(in thousands)	
Deferred tax liabilities-		
Accelerated depreciation	$ 776,953	$ 721,087
Property basis differences	52,242	45,960
Fuel recovery clause	16,148	7,972
Pension and other employee benefits	34,405	25,800
Regulatory assets associated with employee benefit obligations	59,788	27,660
Regulatory assets associated with asset retirement obligations	6,768	6,554
Other	21,712	23,947
Total	968,016	858,980
Deferred tax assets-		
Federal effect of state deferred taxes	30,587	24,277
Postretirement benefits	18,033	17,816
Pension and other employee benefits	65,506	33,015
Property reserve	13,440	15,144
Asset retirement obligations	6,768	6,554
Alternative minimum tax carryforward	18,200	18,420
Other	18,893	17,780
Total	171,427	133,006
Net deferred tax liabilities	796,589	725,974
Portion included in current assets/(liabilities), net	3,134	8,381
Accumulated deferred income taxes	$ 799,723	$ 734,355

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation.

At December 31, 2014, tax-related regulatory assets to be recovered from customers were $56.3 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2014, the tax-related regulatory liabilities to be credited to customers were $3.9 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the average 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 $1.3 million in 2014 and $1.4 million in both 2013 and 2012. At December 31, 2014, all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

	2014	2013	2012
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.5**	3.5	3.3
Non-deductible book depreciation	**0.4**	0.5	0.5
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.2)
AFUDC equity	**(1.8)**	(1.1)	(0.9)
Other, net	**0.1**	(0.1)	(0.2)
Effective income tax rate	**37.1%**	37.6%	37.5%

The decrease in the Company's 2014 effective tax rate is primarily the result of an increase in AFUDC equity which is not taxable.

Unrecognized Tax Benefits

Changes during the year in unrecognized tax benefits were as follows:

	2014	2013	2012
		(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 45**	$ 5,007	$ 2,892
Tax positions increase from current periods	**46**	45	2,630
Tax positions increase/(decrease) from prior periods	**(45)**	(5,007)	515
Reductions due to settlements	**—**	—	(1,030)
Balance at end of year	**$ 46**	$ 45	$ 5,007

The tax positions increase from current periods and decrease from prior periods for 2014 relate primarily to the research and development credit. The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs related to generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

The impact on the Company's effective tax rate, if recognized, is as follows:

	2014	2013	2012
		(in thousands)	
Tax positions impacting the effective tax rate	**$ 46**	$ 45	$ 45
Tax positions not impacting the effective tax rate	**—**	—	4,962
Balance of unrecognized tax benefits	**$ 46**	$ 45	$ 5,007

The tax positions impacting the effective tax rate for all periods presented relate primarily to the research and development credit. The tax positions not impacting the effective tax rate for 2012 relate to the tax accounting method change for repairs related to generation assets. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial for all periods presented. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 federal income tax return and has received a partial acceptance letter from the IRS; however, the IRS has not finalized its audit. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2010.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, in April 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. In September 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company continues to review this guidance; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

At December 31, 2014, the Company had no scheduled maturities of long-term debt due within one year.

Maturities from 2016 through 2019 applicable to total long-term debt are as follows: $110 million in 2016 and $85 million in 2017. There are no scheduled maturities in 2015, 2018, or 2019.

Senior Notes

At each of December 31, 2014 and 2013, the Company had a total of $1.07 billion and $945 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at December 31, 2014.

In September 2014, the Company issued $200 million aggregate principal amount of Series 2014A 4.55% Senior Notes due October 1, 2044. The proceeds were used to repay a portion of the Company's outstanding short-term indebtedness, for general corporate purposes, including the Company's continuous construction program and for repayment at maturity $75 million aggregate principal amount of the Company's Series K 4.90% Senior Notes due October 1, 2014.

Pollution Control Revenue 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 and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2014 and 2013 was $309 million and $296 million, respectively.

In April 2014, the Company executed a loan agreement with Mississippi Business Finance Corporation (MBFC) related to MBFC's issuance of $29.075 million aggregate principal amount of Pollution Control Revenue Refunding Bonds, First Series 2014 (Gulf Power Company Project) due April 1, 2044 for the benefit of the Company. The proceeds were used to redeem $29.075 million aggregate principal amount of MBFC Pollution Control Revenue Refunding Bonds, Series 2003 (Gulf Power Company Project).

In June 2014, the Company reoffered to the public $13 million aggregate principal amount of MBFC Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which had been previously purchased and held by the Company since December 2013.

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. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2014. 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 preference stock are subject to redemption at the option of the Company on or after a specified date (typically five or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, certain series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2014, the Company issued 500,000 shares of common stock to Southern Company and realized proceeds of $50 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Subsequent to December 31, 2014, the Company issued 200,000 shares of common stock to Southern Company and realized proceeds of $20 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an outstanding principal amount of $41 million. There are no agreements or other arrangements among the Southern Company system 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 December 31, 2014, committed credit arrangements with banks were as follows:

Expires					Executable Term-Loans		Due Within One Year	
2015	2016	2017	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$ 80	$ 165	$ 30	$ 275	$ 275	$ 50	$ —	$ 50	$ 30

Subject to applicable market conditions, the Company expects to renew its bank credit arrangements as needed, prior to expiration. Most of the $275 million of unused credit arrangements with banks provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The Company had $69 million of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2014. In addition, at December 31, 2014, the Company had $78 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months. Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2014, the Company was in compliance with these covenants.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Commercial Paper at the End of the Period	
	Amount Outstanding	Weighted Average Interest Rate
	(in millions)	
December 31, 2014	**$ 110**	**0.3%**
December 31, 2013	$ 136	0.2%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2014, 2013, and 2012, the Company incurred fuel expense of $604.6 million, $532.8 million, and $544.9 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under purchased power agreements accounted for as operating leases was $49.5 million, $21.3 million, and $24.6 million for 2014, 2013, and 2012, respectively.

Estimated total minimum long-term commitments at December 31, 2014 were as follows:

	Operating Lease PPAs
	(in millions)
2015	$ 78.7
2016	78.7
2017	78.8
2018	78.9
2019	78.9
2020 and thereafter	270.3
Total	$ 664.3

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 traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. 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

In addition to the operating lease PPAs discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $15.0 million, $18.0 million, and $20.1 million for 2014, 2013, and 2012, respectively.

Estimated total minimum lease payments under these operating leases at December 31, 2014 were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2015	$ 15.1	$ 0.1	$ 15.2
2016	15.0	0.1	15.1
2017	1.4	0.1	1.5
Total	$ 31.5	$ 0.3	$ 31.8

The Company and Mississippi Power jointly entered into an operating lease agreement 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. The Company's share of the lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, was $2.8 million in 2014, $3.1 million in 2013, and $3.6 million in 2012. The Company's annual railcar lease payments for 2015 through 2017 will average approximately $1.6 million. The Company has no lease payment obligations for the period 2018 and thereafter.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2014, there were 195 current and former employees of the Company participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options 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 Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted stock options for 432,371 shares, 285,209 shares, and 244,607 shares, respectively. The weighted average grant-date fair value of stock options granted during 2014, 2013, and 2012, derived using the Black-Scholes stock option pricing model, was $2.20, $2.93, and $3.39, respectively.

The compensation cost and tax benefits related to the grant of Southern Company stock options to the Company's employees and the exercise of stock options are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. No cash proceeds are received by the Company upon the exercise of stock options. The amounts were not material for any year presented.

As of December 31, 2014, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013, and 2012 was $5.2 million, $1.7 million, and $3.8 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.0 million, $0.6 million, and $1.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. As of December 31, 2014, the aggregate intrinsic value for the options outstanding and options exercisable was $11.9 million and $7.7 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on

Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount. Performance share units held by employees of a company undergoing a change in control vest upon the change in control.

For the years ended December 31, 2014, 2013, and 2012, employees of the Company were granted performance share units of 37,829, 30,627, and 29,444, respectively. The weighted average grant-date fair value of performance share units granted during 2014, 2013, and 2012, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $37.54, $40.50, and $41.99, respectively.

The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. For the years ended December 31, 2014, 2013, and 2012, total compensation cost for performance share units recognized in income was approximately $1.0 million annually, with the related tax benefit also recognized in income of $0.4 million annually. The compensation cost and tax benefits related to the grant of Southern Company performance share units 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. As of December 31, 2014, there was $1.3 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 20 months.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2014:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 125	$ —	$ 125
Cash equivalents	18,032	—	—	18,032
Total	$ 18,032	$ 125	$ —	$ 18,157
Liabilities:				
Energy-related derivatives	$ —	$ 72,435	$ —	$ 72,435

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
		(in thousands)		
Assets:				
Energy-related derivatives	$ —	$ 6,962	$ —	$ 6,962
Cash equivalents	15,929	—	—	15,929
Total	$ 15,929	$ 6,962	$ —	$ 22,891
Liabilities:				
Energy-related derivatives	$ —	$ 17,043	$ —	$ 17,043

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2014 and 2013, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice Period**
As of December 31, 2014:	*(in thousands)*			
Cash equivalents:				
Money market funds	$18,032	None	Daily	Not applicable
As of December 31, 2013:				
Cash equivalents:				
Money market funds	$15,929	None	Daily	Not applicable

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2014 and 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	**Fair Value**
	(in thousands)	
Long-term debt:		
2014	**$ 1,369,594**	**$ 1,476,954**
2013	$ 1,233,163	$ 1,261,889

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

10. DERIVATIVES

The 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 its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management 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 testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

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 and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- *Regulatory Hedges* — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- *Not Designated* — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2014, the net volume of energy-related derivative contracts for natural gas positions totaled 84.59 million mmBtu for the Company, with the longest hedge date of 2019 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2014, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2015 are not material. The Company has deferred gains and losses that are expected to be amortized into earnings through 2020.

Derivative Financial Statement Presentation and Amounts

At December 31, 2014 and 2013, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 34**	$4,893	Liabilities from risk management activities	**$36,922**	$ 6,470
	Other deferred charges and assets	**78**	2,069	Other deferred credits and liabilities	**35,502**	10,573
Total derivatives designated as hedging instruments for regulatory purposes		**$ 112**	$6,962		**$72,424**	$17,043

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2014 and 2013.

The derivative contracts of the Company are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related derivative contracts contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Amounts related to energy-related derivative contracts at December 31, 2014 and 2013 are presented in the following tables.

Fair Value					
Assets	**2014**	2013	**Liabilities**	**2014**	2013
	(in thousands)			*(in thousands)*	
Energy-related derivatives presented in the Balance Sheet [(a)]	**$ 125**	$6,962	Energy-related derivatives presented in the Balance Sheet [(a)]	**$72,435**	$17,043
Gross amounts not offset in the Balance Sheet [(b)]	**(123)**	(5,775)	Gross amounts not offset in the Balance Sheet [(b)]	**(123)**	(5,775)
Net energy-related derivative assets	**$ 2**	$1,187	**Net energy-related derivative liabilities**	**$72,312**	$11,268

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2014 and 2013, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2014**	2013	**Balance Sheet Location**	**2014**	2013
		(in thousands)			*(in thousands)*	
Energy-related derivatives:	Other regulatory assets, current	**$(36,922)**	$ (6,470)	Other regulatory liabilities, current	**$ 34**	$4,893
	Other regulatory assets, deferred	**(35,502)**	(10,573)	Other regulatory liabilities, deferred	**78**	2,069
Total energy-related derivative gains (losses)		**$(72,424)**	$(17,043)		**$ 112**	$6,962

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	**2014**	2013	2012	**Statements of Income Location**	**2014**	2013	2012
		(in thousands)				*(in thousands)*	
Interest rate derivatives	**$—**	$—	$—	Interest expense, net of amounts capitalized	**$(606)**	$(769)	$(933)

There was no material ineffectiveness recorded in earnings for any period presented.

For the years ended December 31, 2014, 2013, and 2012, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

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 derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2014, the Company's collateral posted with its derivative counterparties was not material.

At December 31, 2014, the fair value of derivative liabilities with contingent features was $20.5 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $54.5 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2014 and 2013 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2014	**$ 407,132**	**$ 73,888**	**$ 36,743**
June 2014	**383,531**	**68,877**	**34,097**
September 2014	**438,334**	**88,600**	**46,547**
December 2014	**361,485**	**49,850**	**22,789**
March 2013	$ 326,274	$ 51,640	$ 21,792
June 2013	371,173	69,151	32,582
September 2013	399,361	87,776	44,754
December 2013	343,493	56,436	25,301

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

[This page intentionally left blank]

SELECTED FINANCIAL AND OPERATING DATA 2010-2014
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands)	**$ 1,590,482**	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Net Income After Dividends on Preference Stock (in thousands)	**$ 140,176**	$ 124,429	$ 125,932	$ 105,005	$ 121,511
Cash Dividends on Common Stock (in thousands)	**$ 123,200**	$ 115,400	$ 115,800	$ 110,000	$ 104,300
Return on Average Common Equity (percent)	**11.02**	10.30	10.92	9.55	11.69
Total Assets (in thousands)	**$ 4,708,259**	$ 4,337,571	$ 4,177,402	$ 3,871,881	$ 3,584,939
Gross Property Additions (in thousands)	**$ 360,937**	$ 304,778	$ 325,237	$ 337,830	$ 285,379
Capitalization (in thousands):					
Common stock equity	**$ 1,309,590**	$ 1,235,126	$ 1,180,742	$ 1,124,948	$ 1,075,036
Preference stock	**146,504**	146,504	97,998	97,998	97,998
Long-term debt	**1,369,594**	1,158,163	1,185,870	1,235,447	1,114,398
Total (excluding amounts due within one year)	**$ 2,825,688**	$ 2,539,793	$ 2,464,610	$ 2,458,393	$ 2,287,432
Capitalization Ratios (percent):					
Common stock equity	**46.3**	48.6	47.9	45.8	47.0
Preference stock	**5.2**	5.8	4.0	4.0	4.3
Long-term debt	**48.5**	45.6	48.1	50.2	48.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**388,292**	383,980	379,922	378,248	376,561
Commercial	**54,892**	54,567	53,808	53,450	53,263
Industrial	**260**	260	264	273	272
Other	**603**	582	577	565	562
Total	**444,047**	439,389	434,571	432,536	430,658
Employees (year-end)	**1,384**	1,410	1,416	1,424	1,330

SELECTED FINANCIAL AND OPERATING DATA 2010-2014 (continued)
Gulf Power Company 2014 Annual Report

	2014	2013	2012	2011	2010
Operating Revenues (in thousands):					
Residential	**$ 700,442**	$ 632,495	$ 609,454	$ 637,352	$ 707,196
Commercial	**408,401**	395,062	389,936	408,389	439,468
Industrial	**153,167**	138,585	140,490	158,367	157,591
Other	**4,530**	3,858	4,591	4,382	4,471
Total retail	**1,266,540**	1,170,000	1,144,471	1,208,490	1,308,726
Wholesale — non-affiliates	**129,151**	109,386	106,881	133,555	109,172
Wholesale — affiliates	**130,107**	99,577	123,636	111,346	110,051
Total revenues from sales of electricity	**1,525,798**	1,378,963	1,374,988	1,453,391	1,527,949
Other revenues	**64,684**	61,338	64,774	66,421	62,260
Total	**$ 1,590,482**	$ 1,440,301	$ 1,439,762	$ 1,519,812	$ 1,590,209
Kilowatt-Hour Sales (in thousands):					
Residential	**5,362,423**	5,088,828	5,053,724	5,304,769	5,651,274
Commercial	**3,838,148**	3,809,939	3,858,521	3,911,399	3,996,502
Industrial	**1,849,255**	1,700,174	1,725,121	1,798,688	1,685,817
Other	**25,236**	20,946	25,267	25,430	25,602
Total retail	**11,075,062**	10,619,887	10,662,633	11,040,286	11,359,195
Wholesale — non-affiliates	**1,670,121**	1,162,308	977,395	2,012,986	1,675,079
Wholesale — affiliates	**3,283,685**	3,127,350	4,369,964	2,607,873	2,436,883
Total	**16,028,868**	14,909,545	16,009,992	15,661,145	15,471,157
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**13.06**	12.43	12.06	12.01	12.51
Commercial	**10.64**	10.37	10.11	10.44	11.00
Industrial	**8.28**	8.15	8.14	8.80	9.35
Total retail	**11.44**	11.02	10.73	10.95	11.52
Wholesale	**5.23**	4.87	4.31	5.30	5.33
Total sales	**9.52**	9.25	8.59	9.28	9.88
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,865**	13,301	13,303	14,028	15,036
Residential Average Annual Revenue Per Customer	**$ 1,811**	$ 1,653	$ 1,604	$ 1,685	$ 1,882
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,663**	2,663	2,663	2,663	2,663
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,684**	1,729	2,130	2,485	2,544
Summer	**2,424**	2,356	2,344	2,527	2,519
Annual Load Factor (percent)	**51.1**	55.9	56.3	54.5	56.1
Plant Availability Fossil-Steam (percent)*	**89.4**	92.8	82.5	84.7	94.7
Source of Energy Supply (percent):					
Coal	**44.5**	36.4	34.6	49.4	64.6
Gas	**22.2**	23.0	23.5	24.0	17.8
Purchased power —					
From non-affiliates	**28.9**	37.0	40.2	22.3	13.2
From affiliates	**4.4**	3.6	1.7	4.3	4.4
Total	**100.0**	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

DIRECTORS AND OFFICERS
Gulf Power Company 2014 Annual Report

DIRECTORS

S. W. Connally, Jr.
President and Chief Executive Officer
Gulf Power Company
Pensacola, Florida. Elected 2012

Allan G. Bense
Chairman and Chief Executive Officer
Bense Enterprises, Inc.
Panama City, Florida. Elected 2010

Deborah H. Calder
Executive Vice President
Navy Federal Credit Union
Pensacola, Florida. Elected 2010

William C. Cramer, Jr.
President
Bill Cramer Chevrolet Cadillac Buick GMC, Inc.
Panama City, Florida. Elected 2002

Julian B. MacQueen
Founder and Chief Executive Officer
Innisfree Hotels, Inc.
Gulf Breeze, Florida. Elected 2013

J. Mort O'Sullivan, III
Managing Member
Warren Averett
Pensacola, Florida. Elected 2010

Michael T. Rehwinkel
Executive Chairman
EVRAZ North America
Pensacola, Florida. Elected 2013

Winston E. Scott
Senior Vice President for External Relations &
Economic Development
Florida Institute of Technology
Melbourne, Florida. Elected 2003

OFFICERS

S. W. Connally, Jr.
President and Chief Executive Officer
26 Years of Service

Michael L. Burroughs
Vice President – Senior Production Officer
23 Years of Service

P. Bernard Jacob (1)
Vice President – Customer Operations
32 Years of Service

Jim R. Fletcher (2)
Vice President – External Affairs and Corporate Services
29 Years of Service

Wendell E. Smith (2)
Vice President – Power Delivery
31 Years of Service

Richard S. Teel
Vice President and Chief Financial Officer
15 Years of Service

Bentina C. Terry (2)
Vice President – Customer Service and Sales
13 Years of Service

Connie J. Erickson (3)
Comptroller
12 Years of Service

Janet J. Hodnett (4)
Comptroller
34 Years of Service

Susan D. Ritenour
Secretary and Treasurer
33 Years of Service

Terry A. Davis (5)
Assistant Secretary and Assistant Treasurer
28 Years of Service

Stacy R. Kilcoyne
Vice President
37 Years of Service

Melissa K. Caen
Assistant Secretary and Assistant Treasurer
8 Years of Service

(1) Retired effective May 3, 2014.
(2) Effective March 29, 2014.
(3) Resigned effective May 16, 2014.
(4) Elected effective June 7, 2014.
(5) Retiring effective June 30, 2015.

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

Profile
The Company produces and delivers electricity as an integrated utility to both retail and wholesale customers within the State of Florida. The Company sells electricity to approximately 440,000 customers within its service area of approximately 7,500 square miles in the Florida panhandle. In 2014, retail energy sales accounted for 69 percent of the Company's total sales of 16 billion kilowatt-hours.

The Company is a wholly owned subsidiary of The Southern Company, which is the parent company of four traditional operating companies, a wholesale generation subsidiary, and other direct and indirect subsidiaries. There is no established public trading market for the Company's common stock.

Registrar, Transfer Agent, and Dividend Paying Agent
Preference Stock
Computershare, Inc.
P.O. Box 30170
College Station, TX 77842-3170
(800) 554-7626

Trustee, Registrar, and Interest Paying Agent
All series of Senior Notes
The Bank of New York Mellon
Global Corporate Trust
101 Barclay Street, 8 West
New York, New York 10286

All of the outstanding shares of the Company's preference stock are registered in the name of Cede & Co., as nominee for The Depository Trust Company.

Form 10-K
A copy of Form 10-K as filed with the Securities and Exchange Commission will be provided upon written request to the office of the Corporate Secretary at the mailing address below:

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

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

Auditors
Deloitte & Touche LLP
Suite 2000
191 Peachtree Street, N.E.
Atlanta, GA 30303-1924

Legal Counsel
Beggs & Lane
A Registered Limited Liability Partnership
P.O. Box 12950
Pensacola, FL 32591-2950