SCANA CORP
Form 10-K
February 28, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2013

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
	SCANA Corporation (a South Carolina corporation)	
1-8809	South Carolina Electric & Gas Company (a South Carolina corporation)	57-0784499
1-3375	100 SCANA Parkway, Cayce, South Carolina 29033	57-0248695
	(803) 217-9000	

Securities registered pursuant to Section 12(b) of the Act:
SCANA Corporation: Common stock, without par value, registered on The New York Stock Exchange
2009 Series A 7.70% Enhanced Junior Subordinated Notes, registered on The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
South Carolina Electric & Gas Company: Series A Nonvoting Preferred Shares

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
SCANA Corporation x South Carolina Electric & Gas Company x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
SCANA Corporation o South Carolina Electric & Gas Company o

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
SCANA Corporation Yes x No o South Carolina Electric & Gas Company Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
SCANA Corporation Yes x No o South Carolina Electric & Gas Company Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
SCANA Corporation x South Carolina Electric & Gas Company x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Exchange Act Rule 12b-2).

SCANA Corporation	Large accelerated filer x	Accelerated filer o	Non-accelerated filer o	Smaller reporting c
South Carolina Electric & Gas Company	Large accelerated filer o	Accelerated filer o	Non-accelerated filer x	Smaller reporting c

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).
SCANA Corporation Yes o No x South Carolina Electric & Gas Company Yes o No x

The aggregate market value of voting stock held by non-affiliates of SCANA Corporation was $6.85 billion at June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price of $49.10 per share. South Carolina Electric & Gas Company is a wholly owned subsidiary of SCANA Corporation and has no voting stock other than its common stock, all of which is held beneficially and of record by SCANA Corporation. A description of registrants' common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at February 20, 2014
SCANA Corporation	Without Par Value	141,144,841
South Carolina Electric & Gas Company	Without Par Value	40,296,147

Documents incorporated by reference: Specified sections of SCANA Corporation's Proxy Statement, in connection with its 2014 Annual Meeting of Shareholders, are incorporated by reference in Part III hereof.

This combined Form 10-K is separately filed by SCANA Corporation and South Carolina Electric & Gas Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Each registrant makes no representation as to information relating to the other company.

South Carolina Electric & Gas Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and therefore is filing this Form with the reduced disclosure format allowed under General Instruction I(2).

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Annual Report on Form 10-K which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "forecasts," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following:

(1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment;
(2) regulatory actions, particularly changes in rate regulation, regulations governing electric grid reliability and pipeline integrity, environmental regulations, and actions affecting the construction of new nuclear units;
(3) current and future litigation;
(4) changes in the economy, especially in areas served by subsidiaries of SCANA;
(5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial markets;
(6) the impact of conservation and demand side management efforts and/or technological advances on customer usage;
(7) the loss of sales to distributed generation, such as solar photovoltaic systems;
(8) growth opportunities for SCANA's regulated and diversified subsidiaries;
(9) the results of short- and long-term financing efforts, including prospects for obtaining access to capital markets and other sources of liquidity;
(10) the effects of weather, especially in areas where the generation and transmission facilities of SCANA and its subsidiaries (the Company) are located and in areas served by SCANA's subsidiaries;
(11) changes in SCANA's or its subsidiaries' accounting rules and accounting policies;
(12) payment and performance by counterparties and customers as contracted and when due;
(13) the results of efforts to license, site, construct and finance facilities for electric generation and transmission;
(14) maintaining creditworthy joint owners for SCE&G's new nuclear generation project;
(15) the ability of suppliers, both domestic and international, to timely provide the labor, secure processes, components, parts, tools, equipment and other supplies needed, at agreed upon prices, for our construction program, operations and maintenance;
(16) the results of efforts to ensure the physical and cyber security of key assets and processes;
(17) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power;
(18) the availability of skilled and experienced human resources to properly manage, operate, and grow the Company's businesses;
(19) labor disputes;
(20) performance of SCANA's pension plan assets;
(21) changes in taxes;
(22) inflation or deflation;
(23) compliance with regulations;
(24) natural disasters and man-made mishaps that directly affect our operations or the regulations governing them; and

(25) the other risks and uncertainties described from time to time in the periodic reports filed by SCANA or SCE&G with the SEC.

SCANA and SCE&G disclaim any obligation to update any forward-looking statements.

DEFINITIONS

Abbreviations used in this Form 10-K have the meanings set forth below unless the context requires otherwise:

TERM	MEANING
AFC	Allowance for Funds Used During Construction
ANI	American Nuclear Insurers
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
BLRA	Base Load Review Act
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CFTC	Commodity Futures Trading Commission
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CGT	Carolina Gas Transmission Corporation
COL	Combined Construction and Operating License
Company	SCANA, together with its consolidated subsidiaries
Consolidated SCE&G	SCE&G and its consolidated affiliates
Consortium	A consortium consisting of Westinghouse Electric Company LLC and Stone and Webster, Inc., a subsidiary of Chicago Bridge & Iron Company N. V.
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
CWA	Clean Water Act
DHEC	South Carolina Department of Health and Environmental Control
Dodd-Frank	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	United States Department of Energy
DOJ	United States Department of Justice
DOT	United States Department of Transportation
DSM Programs	Demand Side Management Programs
EIZ Credits	South Carolina Capital Investment Tax Credits (formerly known as Economic Impact Zone Income Tax Credits)
ELG Rule	New federal effluent limitation guidelines for steam electric generating units
Energy Marketing	The divisions of SEMI, excluding SCANA Energy
EPA	United States Environmental Protection Agency
EPC Contract	Engineering, Procurement and Construction Agreement dated May 23, 2008
eWNA	Pilot Electric WNA
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GPSC	Georgia Public Service Commission
GWh	Gigawatt hour
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
JEDA	South Carolina Jobs-Economic Development Authority
KVA	Kilovolt ampere

kWh	Kilowatt-hour

TERM	MEANING
Level 1	A fair value measurement using unadjusted quoted prices in active markets for identical assets or liabilities
Level 2	A fair value measurement using observable inputs other than those for Level 1, including quoted prices for similar (not identical) assets or liabilities or inputs that are derived from observable market data by correlation or other means
Level 3	A fair value measurement using unobservable inputs, including situations where there is little, if any, market activity for the asset or liability
LNG	Liquefied Natural Gas
LOC	Lines of Credit
LTECP	SCANA Long-Term Equity Compensation Plan
MATS	Mercury and Air Toxics Standards
MCF or MMCF	Thousand Cubic Feet or Million Cubic Feet
MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units
MW or MWh	Megawatt or Megawatt-hour
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
New Units	Nuclear Units 2 and 3 under construction at Summer Station
NPDES	National Permit Discharge Elimination System
NRC	United States Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NSR	New Source Review
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYSE	The New York Stock Exchange
OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
PHMSA	United States Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Indemnification Act
PRP	Potentially Responsible Party
PSNC Energy	Public Service Company of North Carolina, Incorporated
RCC	Replacement Capital Covenant
RSA	Natural Gas Rate Stabilization Act
Santee Cooper	South Carolina Public Service Authority
SCANA	SCANA Corporation, the parent company
SCANA Energy	A division of SEMI which markets natural gas in Georgia
SCE&G	South Carolina Electric & Gas Company
SCEUC	South Carolina Energy Users Committee
SCI	SCANA Communications, Inc.
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SERC	SERC Reliability Corporation
Southern Natural	Southern Natural Gas Company
Summer Station	V. C. Summer Nuclear Station

TERM	MEANING
Transco	Transcontinental Gas Pipeline Corporation
TSR	Total Shareholder Return
VACAR	Virginia-Carolinas Reliability Group
VIE	Variable Interest Entity
Westinghouse	Westinghouse Electric Company LLC
Williams Station	A.M. Williams Generating Station, owned by GENCO
WNA	Weather Normalization Adjustment

PART I

ITEM 1. BUSINESS

CORPORATE STRUCTURE AND ORGANIZATION

SCANA is a South Carolina corporation created in 1984 as a holding company. SCANA holds directly all of the capital stock of the following subsidiaries, each of which is incorporated in South Carolina.

SCE&G	Engaged in the generation, transmission, distribution and sale of electricity to retail and wholesale customers and the purchase, sale and transportation of natural gas to retail customers
GENCO	Owns Williams Station and sells electricity solely to SCE&G
Fuel Company	Acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances
PSNC Energy	Purchases, sells and transports natural gas to retail customers
CGT	Transports natural gas in South Carolina and southeastern Georgia
SCI	Provides fiber optic communications, ethernet services and data center facilities and builds, manages and leases communications towers in South Carolina, North Carolina and Georgia
SEMI	Markets natural gas, primarily in the Southeast, and provides energy related risk management services. SCANA Energy, a division of SEMI, markets natural gas in Georgia's retail market.
ServiceCare, Inc.	Provides service contracts on home appliances and heating and air conditioning units
SCANA Services, Inc.	Provides administrative, management and other services to SCANA's subsidiaries and business units

SCANA owns one other energy related company that is insignificant and being liquidated.

SCANA and its subsidiaries had full-time, permanent employees as of February 20, 2014 and 2013 of 5,989 and 5,842, respectively.

INVESTOR INFORMATION

SCANA's and SCE&G's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC are available free of charge through SCANA's internet website at www.scana.com (which is not intended as an active hyperlink) as soon as reasonably practicable after these reports are filed or furnished. Information on SCANA's website is not part of this or any other report filed with or furnished to the SEC.

SCANA and SCE&G post information from time to time regarding developments relating to SCE&G's new nuclear project on SCANA's website at www.scana.com (which is not intended to be an active hyperlink; the information on SCANA's website is not a part of this report or any other report or document that SCANA or SCE&G files with or furnishes to the SEC). On SCANA's homepage, there is a yellow box containing a link to the New Nuclear Development section of the website. That section in turn contains a yellow box with a link to recent project news and updates. Some of the information that will be posted from time to time, including the quarterly reports that SCE&G submits to the SCPSC and the ORS in connection with the new nuclear project, may be deemed to be material information that has not otherwise become public, and investors, media and others interested in SCE&G's new nuclear project are encouraged to review this information.

SEGMENTS OF BUSINESS

For information with respect to major segments of business, see Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and the consolidated financial statements for SCANA and SCE&G (Note 12). All such information is incorporated herein by reference.

SCANA does not directly own or operate any significant physical properties. SCANA, through its subsidiaries, is engaged in the functionally distinct operations described below.

Regulated Utilities

SCE&G is engaged in the generation, transmission, distribution and sale of electricity to approximately 678,000 customers and the purchase, sale and transportation of natural gas to approximately 329,000 customers (each as of December 31, 2013). SCE&G's business experiences seasonal fluctuations, with generally higher sales of electricity during the summer and winter months because of air conditioning and heating requirements, and generally higher sales of natural gas during the winter months due to heating requirements. SCE&G's electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 22,600 square miles. More than 3.2 million persons live in the counties where SCE&G conducts its business. Resale customers include municipalities, electric cooperatives, other investor-owned utilities, registered marketers and federal and state electric agencies. Predominant industries served by SCE&G include chemicals, educational services, paper products, food products, lumber and wood products, health services, textile manufacturing, rubber and miscellaneous plastic products and fabricated metal products.

PSNC Energy purchases, sells and transports natural gas to approximately 509,000 residential, commercial and industrial customers (as of December 31, 2013). PSNC Energy serves 28 franchised counties covering 12,000 square miles in North Carolina. The predominant industries served by PSNC Energy include educational services, food products, health services, automotive, chemicals, non-woven textiles, electrical generation and construction.

CGT operates as an open access, transportation-only interstate pipeline company regulated by FERC. CGT operates in southeastern Georgia and in South Carolina and has interconnections with Southern Natural at Port Wentworth, Georgia and with Southern LNG, Inc. at Elba Island, near Savannah, Georgia. CGT also has interconnections with Southern Natural in Aiken County, South Carolina, and with Transco in Cherokee and Spartanburg counties, South Carolina. CGT's customers include SCE&G (which uses natural gas for electricity generation and for gas distribution to retail customers), SEMI (which markets natural gas to industrial and sale for resale customers, primarily in the Southeast), municipalities, county gas authorities, federal and state agencies, marketers, power generators and industrial customers primarily engaged in the manufacturing or processing of ceramics, paper, metal, and textiles.

Nonregulated Businesses

SEMI markets natural gas primarily in the southeast and provides energy-related risk management services. SCANA Energy, a division of SEMI, sells natural gas to approximately 454,000 customers (as of December 31, 2013, and includes approximately 68,000 customers in its regulated division) in Georgia's natural gas market. In third quarter 2013, SCANA Energy's contract to serve as Georgia's regulated provider of natural gas was renewed by the GPSC through August 31, 2015. SCANA Energy's total customer base represents an approximately 30% share of the approximately 1.5 million customers in Georgia's deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in Georgia.

SCI owns and operates a 1,125 mile fiber optic telecommunications network and ethernet network and data center facilities in South Carolina. Through a joint venture, SCI has an interest in an additional 2,280 miles of fiber in South Carolina, North Carolina and Georgia. SCI also provides tower site construction, management and rental services and sells towers in South Carolina and North Carolina. SCI leases fiber optic capacity, data center space and tower space to certain affiliates at market rates.

The preceding Corporate Structure and Organization section describes other regulated and nonregulated businesses owned by SCANA.

COMPETITION

For a discussion of the impact of competition, see the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

CAPITAL REQUIREMENTS

SCANA's regulated subsidiaries, including SCE&G, require cash to fund operations, construction programs and dividend payments to SCANA. SCANA's nonregulated subsidiaries require cash to fund operations and dividend payments to SCANA. To replace existing plant investment and to expand to meet future demand for electricity and gas, SCANA's regulated subsidiaries must attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their construction programs, rate increases will be sought.

The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief, when requested.

For a discussion of various rate matters and their impact on capital requirements, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G and Note 2 to the consolidated financial statements for SCANA and SCE&G.

During the period 2014-2016, SCANA and SCE&G expect to meet capital requirements through internally generated funds, issuance of equity and short-term and long-term borrowings. SCANA and SCE&G expect that they have or can obtain adequate sources of financing to meet their projected cash requirements for the next 12 months and for the foreseeable future.

For a discussion of cash requirements for construction and nuclear fuel expenditures, contractual cash obligations, financing limits, financing transactions and other related information, see the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Ratios of earnings to fixed charges for each of the five years ended December 31, 2013, were as follows:

December 31,	2013	2012	2011	2010	2009
SCANA	3.22	2.93	2.87	2.92	2.84
SCE&G	3.48	3.29	3.13	3.18	3.25

ELECTRIC OPERATIONS

Electric Sales

SCE&G's sales of electricity and margins earned from the sale of electricity by customer classification as percentages of electric revenues for 2012 and 2013 were as follows:

	Sales				Margins			
Customer Classification	2012		2013		2012		2013	
Residential	43	%	44	%	50	%	50	%
Commercial	32	%	33	%	33	%	33	%
Industrial	17	%	18	%	13	%	14	%
Sales for resale	6	%	2	%	2	%	1	%
Other	2	%	3	%	2	%	2	%
Total	100	%	100	%	100	%	100	%

Sales for resale include sales to three municipalities and one electric cooperative. Short-term system sales were not significant for any period presented.

During 2013 SCE&G experienced a net increase of approximately 8,000 electric customers (growth rate of 1.2%), increasing its total electric customers to approximately 678,000 at year end.

For the period 2014-2016, SCE&G projects total territorial kWh sales of electricity to increase 0.6% annually (assuming normal weather), total retail sales growth of 0.6% annually (assuming normal weather), total electric customer base to increase 1.8% annually and territorial peak load (summer, in MW) to increase 1.9% annually. SCE&G projects a retail kWh sales decrease of approximately 0.2% and customer growth of 1.1% from 2013 to 2014. SCE&G's goal is to maintain a planning reserve margin of between 14% and 20%, however, weather and other factors affect territorial peak load and can cause actual generating capacity on any given day to fall below the reserve margin goal.

Electric Interconnections

SCE&G purchases all of the electric generation of GENCO's Williams Station under a Unit Power Sales Agreement which has been approved by FERC. Williams Station has a net generating capacity (summer rating) of 605 MW.

SCE&G's transmission system, which extends over a large part of the central, southern and southwestern portions of South Carolina, interconnects with Duke Energy Carolinas, LLC, Duke Energy Progress, Inc., Santee Cooper, Georgia Power Company and the Southeastern Power Administration's Clarks Hill (Thurmond) Project. SCE&G is a member of VACAR, one of several geographic divisions within the SERC. SERC is one of eight regional entities with delegated authority from NERC for the purpose of proposing and enforcing reliability standards approved by FERC. SERC is divided geographically into five diverse sub-regions that are identified as Central, Delta, Gateway, Southeastern and VACAR. The regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. For a discussion of the impact certain legislative and regulatory initiatives may have on SCE&G's transmission system, see Electric Operations within the Overview section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

Fuel Costs and Fuel Supply

The average cost of various fuels and the weighted average cost of all fuels (including oil) for the years 2011-2013 follow:

	Cost of Fuel Used		
	2011	2012	2013
Per MMBTU:			
Nuclear	$0.88	$0.94	$1.11
Coal	4.47	4.49	4.28
Natural Gas	4.86	3.71	4.63
All Fuels (weighted average)	3.80	3.56	3.53
Per Ton: Coal	109.91	111.72	104.63
Per MCF: Gas	5.01	3.80	4.69

The sources and percentages of total MWh generation by each category of fuel for the years 2011-2013 and the estimates for the years 2014-2016 follow:

	% of Total MWh Generated					
	Actual			Estimated		
	2011	2012	2013	2014	2015	2016
Coal	50 %	50 %	45 %	50 %	49 %	45 %
Nuclear	19 %	19 %	24 %	21 %	21 %	24 %
Hydro	3 %	3 %	4 %	4 %	4 %	4 %
Natural Gas & Oil	28 %	28 %	26 %	24 %	25 %	26 %
Biomass	—	—	1 %	1 %	1 %	1 %
Total	100 %	100 %	100 %	100 %	100 %	100 %

In 2013, the Company used coal to generate electricity at six fossil fuel-fired plants, including its cogeneration facility located in Charleston, South Carolina. Unit trains and, in some cases, trucks and barges delivered coal to these plants. SCE&G completed the retirement of one of these plants (comprised of three units) in 2012 and 2013 and intends to retire certain other coal-fired generating units by 2018, subject to future developments in environmental regulations, among other matters. One of the units to be retired by 2018 was fueled with coal prior to 2013, but is expected to be fueled exclusively with natural gas until its retirement.

Coal is primarily obtained through long-term supply contracts. Long-term contracts exist with suppliers located in eastern Kentucky, Tennessee and West Virginia. These contracts provide for approximately 2.8 million tons annually. Sulfur restrictions on the contract coal range from 1.0% to 1.6%. These contracts expire at various times through 2016. Spot market purchases may occur when needed or when prices are believed to be favorable.

SCANA and SCE&G believe that SCE&G's operations comply with all applicable regulations relating to the discharge of sulfur dioxide and nitrogen oxide. See additional discussion at Environmental Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G, for itself and as agent for Santee Cooper, and Westinghouse are parties to a fuel alliance agreement and contracts for fuel fabrication and related services. Under these contracts, SCE&G has to supply enriched product to Westinghouse and Westinghouse will supply nuclear fuel assemblies for Summer Station Unit 1 and the New Units. Westinghouse will be SCE&G's exclusive provider of such fuel assemblies on a cost-plus basis. The fuel assemblies to be delivered under the contracts are expected to supply the nuclear fuel requirements of Summer Station Unit 1 and the New Units through 2033. SCE&G is dependent upon Westinghouse for providing fuel assemblies for the new AP1000 reactors in the New Units in the current and anticipated future absence of other commercially viable sources.

The Consortium currently provides maintenance and engineering support to Summer Station Unit 1 under a services alliance agreement. Although SCE&G has provided the Consortium with notice of its election to terminate the existing agreement, it is anticipated that SCE&G will enter into new agreements to provide similar support services to Summer Station Unit 1 and to the New Units upon their completion and commencement of commercial operation. Those new agreements may, but will not necessarily, be between SCE&G and the Consortium.

In addition, SCE&G has contracts covering its nuclear fuel needs for uranium, conversion services and enrichment services. These contracts have varying expiration dates through 2024. SCE&G believes that it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services and that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of its nuclear generating units.

SCE&G can store spent nuclear fuel on-site until at least 2017 and has commenced construction of a dry cask storage facility to accommodate the spent fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available. In addition, Summer Station Unit 1 has sufficient on-site storage capacity to permit storage of the entire reactor core in the event that complete unloading should become desirable or necessary. For information about the contract with the DOE regarding disposal of spent fuel, see Hazardous and Solid Wastes within the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

GAS OPERATIONS

Gas Sales-Regulated

Regulated sales of natural gas by customer classification as a percent of total regulated gas revenues sold or transported for 2012 and 2013 were as follows:

	SCANA				SCE&G			
Customer Classification	2012		2013		2012		2013	
Residential	54.7	%	55.6	%	44.3	%	43.5	%
Commercial	26.1	%	26.0	%	27.5	%	27.4	%
Industrial	11.8	%	12.5	%	22.3	%	25.6	%
Transportation Gas	7.4	%	5.9	%	5.9	%	3.5	%
Total	100.0	%	100.0	%	100.0	%	100.0	%

For the three-year period 2014-2016, SCANA projects total consolidated sales of regulated natural gas in MMBTUs to increase 1.4% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 2.1%, commercial of 0.8% and industrial of 0.8%.

For the three-year period 2014-2016, SCE&G projects total consolidated sales of regulated natural gas in MMBTUs to increase 0.8% annually (excluding transportation and assuming normal weather). Annual projected increases over such period in MMBTU sales include residential of 1.0%, commercial of 0.6% and industrial of 1.0%.

For the three-year period 2014-2016, SCANA's and SCE&G's total consolidated regulated natural gas customer base is projected to increase annually 2.3% and 1.9%, respectively. During 2013 SCANA recorded a net increase of approximately 18,000 regulated gas customers (growth rate of 2.2%), increasing its regulated gas customers to approximately 837,000. Of this increase, SCE&G recorded a net increase of approximately 7,000 gas customers (growth rate of 2.1%), increasing its total gas customers to approximately 329,000 (as of December 31, 2013).

Demand for gas changes primarily due to weather and the price relationship between gas and alternate fuels.

Gas Cost, Supply and Curtailment Plans

SCE&G purchases natural gas under contracts with producers and marketers in both the spot and long-term markets. The gas is delivered to South Carolina through firm transportation agreements with Southern Natural (expiring in 2014 and 2018), Transco (expiring in 2017) and CGT (expiring in 2014, 2018, 2023 and 2026). The maximum daily volume of gas that SCE&G is entitled to transport under these contracts is 222,404 MMBTU from Southern Natural, 64,652 MMBTU from Transco and 425,929 MMBTU from CGT. Additional natural gas volumes may be delivered to SCE&G’s system as capacity is available through interruptible transportation.

The daily volume of gas that SEMI is entitled to transport under service agreements with CGT (expiring in 2016, 2017 and 2023) on a firm basis is 82,615 MMBTU.

SCE&G purchased natural gas, including fixed transportation, at an average cost of $5.35 per MCF during 2013 and $4.73 per MCF during 2012.

SCE&G was allocated 5,382 MMCF of natural gas storage capacity on the systems of Southern Natural and Transco. Approximately 4,039 MMCF of gas were in storage on December 31, 2013. To meet the requirements of its high priority natural gas customers during periods of maximum demand, SCE&G supplements its supplies of natural gas with two LNG liquefaction and storage facilities. The LNG plants are capable of storing the liquefied equivalent of 1,880 MMCF of natural gas. Approximately 1,635 MMCF (liquefied equivalent) of gas were in storage on December 31, 2013.

PSNC Energy purchases natural gas under contracts with producers and marketers on a short-term basis at market based prices and on a long-term basis for reliability assurance at first of the month index prices plus a reservation charge in certain cases. Transco transports natural gas to North Carolina through transportation agreements with varying expiration dates through 2032. On a peak day, PSNC Energy is capable of receiving daily transportation volumes of natural gas under these contracts, utilizing firm contracts of 610,062 MMBTU from Transco.

PSNC Energy purchased natural gas, including fixed transportation, at an average cost of $5.13 per MMBTU during 2013 compared to $4.65 per MMBTU during 2012.

To meet the requirements of its high priority natural gas customers during periods of maximum demand, PSNC Energy supplements its supplies of natural gas with underground natural gas storage services and LNG peaking services. Underground natural gas storage service agreements with Dominion Transmission, Inc., Columbia Gas Transmission, Transco and Spectra Energy provide for storage capacity of approximately 13,000 MMCF. Approximately 10,000 MMCF of gas were in storage under these agreements at December 31, 2013. In addition, PSNC Energy’s LNG facility can store the liquefied equivalent of 1,000 MMCF of natural gas with regasification capability of approximately 100 MMCF per day. Approximately 900 MMCF (liquefied equivalent) of gas were in storage at December 31, 2013. LNG storage service agreements with Transco, Cove Point LNG and Pine Needle LNG provide for 1,300 MMCF (liquefied equivalent) of storage space. Approximately 1,100 MMCF (liquefied equivalent) were in storage under these agreements at December 31, 2013.

SCANA and SCE&G believe that supplies under long-term contracts and supplies available for spot market purchase are adequate to meet existing customer demands and to accommodate growth.

Gas Marketing-Nonregulated

SEMI markets natural gas and provides energy-related risk management services primarily in the Southeast. In addition, SCANA Energy, a division of SEMI, markets natural gas to approximately 454,000 customers (as of December 31, 2013) in Georgia’s natural gas market. SCANA Energy’s total customer base represents an approximate 30% share of the approximately 1.5 million customers in Georgia’s deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state.

Risk Management

For a discussion of risk management policies and procedures, see Note 6 to the consolidated financial statements for SCANA and SCE&G.

REGULATION

For a discussion of legislative and regulatory initiatives being implemented that will affect SCE&G’s transmission system, see Electric Operations within the Overview section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

For a discussion of the regulatory jurisdictions to which SCANA and its subsidiaries are subject, see the Regulatory Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

SCE&G holds licenses under the Federal Power Act for each of its hydroelectric projects. The licenses expire as follows:

Project	License Expiration
Saluda (Lake Murray)	2014
Fairfield Pumped Storage/Parr Shoals	2020
Stevens Creek	2025
Neal Shoals	2036

SCE&G is presently operating the Saluda hydroelectric project under an annual license (scheduled to expire in August) while its long-term re-licensing application is being reviewed by FERC.

At the termination of a license under the Federal Power Act, FERC may extend or issue a new license to the previous licensee, or may issue a license to another applicant, or the federal government may take over the related project. If the federal government takes over a project or if FERC issues a license to another applicant, the federal government or the new licensee, as the case may be, must pay the previous licensee an amount equal to its net investment in the project, not to exceed fair value, plus severance damages.

RATE MATTERS

For a discussion of the impact of various rate matters, see the Regulatory Matters section of Management’s Discussion and Analysis of Financial Condition and Results of Operations for SCANA and SCE&G, and Note 2 to the consolidated financial statements for SCANA and SCE&G.

Prior to the first billing cycle of January 2014, SCE&G's retail electric rates for its residential and certain small commercial customers included an eWNA approved by the SCPSC, which largely mitigated the impact of weather on electric margins. In connection with a December 2013 SCPSC order, SCE&G discontinued the eWNA.

SCE&G’s retail electric rates include certain costs associated with its DSM Programs as authorized by the SCPSC. More specifically, these rates include the costs and lost net margin revenue associated with DSM Programs, along with an incentive for investing in such programs.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11%.

In May 2011 and in November 2012, the SCPSC approved updated capital cost schedules sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs and revised substantial completion dates for the New Units, and included amounts to resolve certain claims. Details of these SCPSC approvals are further described in Notes 2 and 10 to the consolidated financial statements for SCANA and SCE&G.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates and authorized SCE&G an allowed return on common equity of 10.25% (related to non-BLRA expenditures). The SCPSC also approved a mid-period reduction to the cost of fuel component in rates, as well as a reduction in the DSM Programs component rider to retail rates, among other things. See Note 2 to the consolidated financial statements for SCANA and SCE&G for additional details.

SCE&G’s gas rate schedules for its residential, small commercial and small industrial customers include a WNA approved by the SCPSC, which is in effect for bills rendered for billing cycles in November through April. The WNA increases tariff rates if weather is warmer than normal and decreases rates if weather is colder than normal. The WNA does not change the seasonality of gas revenues, but reduces fluctuations in revenues and earnings caused by abnormal weather.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows PSNC Energy to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Fuel Cost Recovery Procedures

The SCPSC’s fuel cost recovery procedure determines the fuel component in SCE&G’s retail electric base rates annually based on projected fuel costs for the ensuing 12-month period, adjusted for any over-collection or under-collection from the preceding 12-month period. The statutory definition of fuel costs includes certain variable environmental costs, such as ammonia, lime, limestone and catalysts consumed in reducing or treating emissions. The definition also includes the cost of emission allowances used for sulfur dioxide, nitrogen oxide, mercury and particulates. SCE&G may request a formal proceeding concerning its fuel costs at any time. SCPSC proceedings related to SCE&G's cost of fuel component are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

SCE&G’s natural gas tariffs include a PGA clause that provides for the recovery of actual gas costs incurred, including transportation costs. SCE&G’s gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average. SCPSC proceedings related to SCE&G's natural gas tariffs are described in Note 2 to the consolidated financial statements for SCANA and SCE&G.

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs, including gas costs that were uncollectible from certain customers. The Rider D rate mechanism also allows it to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy’s rates are established using a benchmark cost of gas approved by the NCUC, which may be adjusted periodically to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collections of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy’s gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption. NCUC proceedings related to PSNC Energy's rates are described in Note 2 to the consolidated financial statements for SCANA.

ENVIRONMENTAL MATTERS

Federal and state authorities have imposed environmental regulations and standards relating primarily to air emissions, wastewater discharges and solid, toxic and hazardous waste management. Developments in these areas may require that equipment and facilities be modified, supplemented or replaced. The ultimate effect of these regulations and standards upon existing and proposed operations cannot be predicted. For a more complete discussion of how these regulations and standards impact SCANA and SCE&G, see the Environmental Matters section of Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 10 to the consolidated financial statements for SCANA and SCE&G.

OTHER MATTERS

For a discussion of SCE&G's insurance coverage for Summer Station Unit 1 and the New Units, see Note 10 to the consolidated financial statements for SCANA and SCE&G.

ITEM 1A. RISK FACTORS

The risk factors that follow relate in each case to SCANA and its subsidiaries, and where indicated the risk factors also relate to SCE&G and its consolidated affiliates.

Commodity price changes, delays and other factors may affect the operating cost, capital expenditures and competitive positions of the Company's and Consolidated SCE&G's energy businesses, thereby adversely impacting results of operations, cash flows and financial condition.

Our energy businesses are sensitive to changes in coal, natural gas, uranium and other commodity prices (as well as their transportation costs) and availability. Any such changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Consolidated SCE&G is permitted to recover the prudently incurred cost of purchased power and fuel (including transportation) used in electric generation through retail customers' bills, but purchased power and fuel cost increases affect electric prices and therefore the competitive position of electricity against other energy sources. In addition, when natural gas prices are low enough relative to coal to require the dispatch of gas-fired electric generation ahead of coal-fired electric generation, higher inventories of coal, with related increased carrying costs, may result. This may adversely affect our results of operations, cash flows and financial position.

In the case of regulated natural gas operations, costs prudently incurred for purchased gas and pipeline capacity may be recovered through retail customers' bills. However, in both our regulated and deregulated natural gas markets, increases in gas costs affect total retail prices and therefore the competitive position of gas relative to electricity and other forms of energy. Accordingly, customers able to do so may switch to alternative forms of energy and reduce their usage of gas from the Company and Consolidated SCE&G. Customers unable to switch to alternative fuels or suppliers may reduce their usage of gas from the Company and Consolidated SCE&G.

Certain construction-related commodities, such as copper and aluminum used in our transmission and distribution lines and in our electrical equipment, and steel, concrete and rare earth elements, have experienced significant price fluctuations due to changes in worldwide demand. To operate our air emissions control equipment, we use significant quantities of ammonia, limestone and lime. With EPA-mandated industry-wide compliance requirements for air emissions controls, increased demand for these reagents, combined with the increased demand for low sulfur coal, may result in higher costs for coal and reagents used for compliance purposes.

The costs of large capital projects, such as the Company's and Consolidated SCE&G's construction for environmental compliance and its construction of the New Units and associated transmission, are significant and are subject to a number of risks and uncertainties that may adversely affect the cost, timing and completion of the projects.

The Company's and Consolidated SCE&G's businesses are capital intensive and require significant investments in energy generation and in other internal infrastructure projects, including projects for environmental compliance. For example, SCE&G and Santee Cooper have agreed to jointly own, contract the design and construction of, and operate the New Units, which will be two 1,250 MW (1,117 MW, net) nuclear units at SCE&G's Summer Station, in pursuit of which they have committed and are continuing to commit significant resources. In addition, construction of significant new transmission infrastructure is necessary to support the New Units and is under way as an integral part of the project. Achieving the intended benefits of any large construction project is subject to many uncertainties. For instance, the ability to adhere to established budgets and timeframes may be affected by many variables, such as the regulatory and legal processes associated with securing permits and licenses and necessary amendments to them within projected timeframes, the availability of labor and materials at estimated costs, the availability and cost of financing, and weather. There also may be contractor or supplier performance issues or adverse changes in their creditworthiness, and unforeseen difficulties meeting critical regulatory requirements. There may be unforeseen engineering problems or unanticipated changes in project design or scope. Our ability to complete construction projects (including new baseload generation) as well as our ability to maintain current operations at reasonable cost could be affected by the availability of key components or commodities, increases in the price of or the unavailability of labor, commodities or other materials, increases in lead times for components, new or enhanced environmental requirements, supply chain failures (whether resulting from the foregoing or other factors), and disruptions in the transportation of components, commodities and fuels. Some of the foregoing issues have been experienced in the construction of the New Units. A discussion of certain of those matters can be found under New Nuclear Construction Matters in Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for SCANA and SCE&G.

Should the construction of the New Units materially and adversely deviate from the schedules, estimates, and projections submitted to and approved by the SCPSC pursuant to the BLRA, the SCPSC could disallow the additional capital costs that result from the deviations to the extent that it is deemed that the Company's failure to anticipate or avoid the deviation, or to minimize the resulting expenses, was imprudent, considering the information available at the time. Depending upon the magnitude of any such disallowed capital costs, the Company could be moved to evaluate the prudency of continuation, adjustment to, or termination of the New Units project.

Furthermore, jointly owned projects, such as the current construction of the New Units, are subject to the risk that one or more of the joint owners becomes either unable or unwilling to continue to fund project financial commitments, new joint owners cannot be secured at equivalent financial terms, or changes in the joint ownership make-up will increase project costs and/or delay the completion.

To the extent that delays occur, costs become unrecoverable, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows and financial condition may be adversely affected.

The use of derivative instruments could result in financial losses and liquidity constraints. The Company and Consolidated SCE&G do not fully hedge against financial market risks or price changes in commodities. This could result in increased costs, thereby resulting in lower margins and adversely affecting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G use derivative instruments, including futures, forwards, options and swaps, to manage our financial market risks. The Company also uses such derivative instruments to manage certain commodity (i.e. natural gas) market risk. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities and financial contracts or if a counterparty fails to perform under a contract.

The Company strives to manage commodity price exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). We do not hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility or our hedges are not effective, results of operations, cash flows and financial condition may be diminished.

Furthermore, Dodd-Frank affects the use and reporting of derivative instruments. The regulations under this new legislation provide for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and require numerous rule-makings by the CFTC and the SEC to implement. The Company and Consolidated SCE&G have determined that they meet the end-user exception to mandatory clearing of swaps under Dodd-Frank. In addition, the Company and Consolidated SCE&G have taken steps to ensure that they are not the party required to report these transactions in real-time (the "reporting party") by transacting solely with swap dealers, major swap participants and financial institutions, when possible, as well as entering into reporting party agreements with counterparties who also are not swap dealers, major swap participants or financial institutions, which establishes that those counterparties are obligated to report the transactions in accordance with applicable Dodd-Frank regulations. While these actions minimize the reporting obligations of the Company, they do not eliminate required recordkeeping for any Dodd-Frank regulated transactions. Moreover, the Company retains reporting responsibility for certain types of swaps, such as the annual reporting of trade options. Despite qualifying for the end-user exception to mandatory clearing and ensuring that neither the Company nor Consolidated SCE&G is the reporting party to a transaction required to be reported in real-time, we cannot predict when the final regulations will be issued or what requirements they will impose.

Changing and complex laws and regulations to which the Company and Consolidated SCE&G are subject could adversely affect revenues, increase costs, or curtail activities, thereby adversely impacting results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G operate under the regulatory authority of the United States government and its various regulatory agencies, including the FERC, NRC, SEC, IRS, EPA, CFTC and PHMSA. In addition, the Company and Consolidated SCE&G are subject to regulation by the state governments of South Carolina, North Carolina and Georgia via regulatory agencies, state environmental commissions, and state employment commissions. Accordingly, the Company and Consolidated SCE&G must comply with extensive federal, state and local laws and regulations. Such governmental oversight and regulation broadly and materially affect the operation of our business. In addition to many other aspects of our business, these requirements impact the licensing, siting, construction and operation of facilities. They affect our management of safety, the reliability of our electric and natural gas transmission systems, the physical and cyber security of key assets, customer conservation through DSM Programs, information security, the issuance of securities and borrowing of money, financial reporting, interactions among affiliates, the payment of dividends and employment programs and practices. Changes to governmental regulations are continual and potentially costly to effect compliance. We cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's or Consolidated SCE&G's businesses.

Furthermore, changes in or uncertainty in monetary, fiscal, or regulatory policies of the Federal government may adversely affect the debt and equity markets and the economic climate for the nation, region or particular industries, such as ours or those of our customers. The Company and Consolidated SCE&G could be adversely impacted by changes in tax policy, such as the loss of Production Tax Credits related to the construction of the New Units.

The Company and Consolidated SCE&G are subject to extensive rate regulation which could adversely affect operations. Large capital projects, DSM Programs results and/or increases in operating costs may lead to requests for regulatory relief, such as rate increases, which may be denied, in whole or part, by rate regulators. Rate increases may also result in reductions in customer usage of electricity or gas, legislative action and lawsuits.

SCE&G's electric operations in South Carolina and the Company's gas distribution operations in South Carolina and North Carolina are regulated by state utilities commissions. In addition, the construction of the New Units by SCE&G is subject to rate regulation by the SCPSC via the BLRA. The Company's interstate gas pipeline, SCE&G's electric transmission system and Consolidated SCE&G's generating facilities are subject to extensive regulation and oversight from the FERC, NRC and SCPSC. Our gas marketing operations in Georgia are subject to state regulatory oversight and, for a portion of its operations, to rate regulation. There can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as market conditions evolve. Although we believe that we have constructive relationships with the regulators, our ability to obtain rate treatment that will allow us to maintain reasonable rates of return is dependent upon regulatory determinations, and there can be no assurance that we will be able to implement rate adjustments when sought.

The Company and Consolidated SCE&G are subject to numerous environmental laws and regulations that require significant capital expenditures, can increase our costs of operations and may impact our business plans or expose us to environmental liabilities.

The Company and Consolidated SCE&G are subject to extensive federal, state and local environmental laws and regulations, including those relating to water quality and air emissions (such as reducing nitrogen oxide, sulfur dioxide, mercury and particulate matter). Some form of regulation is expected at the federal and state levels to impose regulatory requirements specifically directed at reducing GHG emissions from fossil fuel-fired electric generating units. On September 20, 2013, the EPA re-proposed NSPS for emissions of carbon dioxide from newly constructed fossil fuel-fired electric generating units. Standards, regulations, or guidelines are also expected for existing units by June 1, 2014, to be made final no later than June 1, 2015. A number of bills have been introduced in Congress that seek to require GHG emissions reductions from fossil fuel-fired electric generation facilities, natural gas facilities and other sectors of the economy, although none have yet been enacted. On February 16, 2012, the EPA issued the finalized MATS for power plants that requires reduced emissions from new and existing coal and oil-fired electric utility steam generating facilities. The EPA has proposed requirements for cooling water intake structures to meet the best technology available, and the EPA presently is drafting a final rule regarding the handling of coal ash and other combustion by-products produced by power plant operations. Furthermore, the EPA has proposed new standards under the CWA governing effluent limitation guidelines for electric generating units.

Compliance with these environmental laws and regulations requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emissions fees and permitting at our facilities. These expenditures have been significant in the past and are expected to continue or even increase in the future. Changes in compliance requirements or more restrictive interpretations by governmental authorities of existing requirements may impose additional costs on us (such as the clean-up of MGP sites or additional emission allowances) or require us to incur additional capital expenditures or curtail some of our cost savings activities (such as the recycling of fly ash and other coal combustion products for beneficial use). Compliance with any GHG emission reduction requirements, including any mandated renewable portfolio standards, also may impose significant costs on us, and the resulting price increases to our customers may lower customer consumption. Such costs of compliance with environmental regulations could negatively impact our industry, our business and our results of operations and financial position, especially if emissions or discharge limits are reduced or more onerous permitting requirements or additional regulatory requirements are imposed.

Renewable and/or alternative electric generation portfolio standards may be enacted at the federal or state level. Some states already have them, though currently South Carolina does not. Such standards could direct us to build or otherwise acquire generating capacity derived from renewable/alternative energy sources (generally, renewable energy such as biomass, solar, wind and tidal, and excluding fossil fuels, nuclear or hydro facilities). Such renewable/alternative energy may not be readily available in our service territories, if at all, and could be extremely costly to build, acquire, and operate. Resulting increases in the price of electricity to recover the cost of these types of generation, if approved by regulatory commissions, could result in lower usage of electricity by our customers. Although we cannot predict whether such standards will be adopted at the federal level or in South Carolina or their specifics if adopted, compliance with such potential portfolio standards could significantly impact our industry, our capital expenditures, and our results of operations and financial position.

The compliance costs of these environmental laws and regulations are important considerations in the Company's and Consolidated SCE&G's strategic planning and, as a result, significantly affect the decisions to construct, operate, and retire facilities, including generating facilities. In effecting compliance with MATS, SCE&G announced in 2012 that six of its oldest and smallest coal-fired units would be taken off-line or temporarily switched from coal to natural gas prior to closure in 2018. One of these units was retired in late 2012. Two other of these units were retired in late 2013.

The Company and Consolidated SCE&G are vulnerable to interest rate increases, which would increase our borrowing costs, and may not have access to capital at favorable rates, if at all. Additionally, potential disruptions in the capital and credit markets may further adversely affect the availability and cost of short-term funds for liquidity requirements and our ability to meet long-term commitments; each could in turn adversely affect our results of operations, cash flows and financial condition.

The Company and Consolidated SCE&G rely on the capital markets, particularly for publicly offered debt and equity, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs if internal funds are not available from operations. Changes in interest rates affect the cost of borrowing. The Company’s and Consolidated SCE&G’s business plans, which include significant investments in energy generation and other internal infrastructure projects, reflect the expectation that we will have access to the capital markets on satisfactory terms to fund commitments. Moreover, the ability to maintain short-term liquidity by utilizing commercial paper programs is dependent upon maintaining satisfactory short-term debt ratings and the existence of a market for our commercial paper generally.

The Company’s and Consolidated SCE&G’s ability to draw on our respective bank revolving credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments and on our ability to timely renew such facilities. Those banks may not be able to meet their funding commitments to the Company or Consolidated SCE&G if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from us and other borrowers within a short period of time. Longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could adversely affect our access to liquidity needed for our business. Any disruption could require the Company and Consolidated SCE&G to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other discretionary uses of cash. Disruptions in capital and credit markets also could result in higher interest rates on debt securities, limited or no access to the commercial paper market, increased costs associated with commercial paper borrowing or limitations on the maturities of commercial paper that can be sold (if at all), increased costs under bank credit facilities and reduced availability thereof, and increased costs for certain variable interest rate debt securities of the Company and Consolidated SCE&G.

Disruptions in the capital markets and its actual or perceived effects on particular businesses and the greater economy also adversely affect the value of the investments held within SCANA’s pension trust. A significant long-term decline in the value of these investments may require us to make or increase contributions to the trust to meet future funding requirements. In addition, a significant decline in the market value of the investments may adversely impact the Company’s and Consolidated SCE&G’s results of operations, cash flows and financial position, including its shareholders’ equity.

A downgrade in the credit rating of SCANA or any of SCANA's subsidiaries, including SCE&G, could negatively affect our ability to access capital and to operate our businesses, thereby adversely affecting results of operations, cash flows and financial condition.

Various rating agencies rate SCANA's long-term senior unsecured debt, SCE&G's long-term senior secured debt, and the long-term senior unsecured debt of PSNC Energy as investment grade. In addition, ratings agencies maintain ratings on the short-term debt of SCANA, SCE&G, Fuel Company (which ratings are based upon the guarantee of SCE&G) and PSNC Energy. If these rating agencies were to lower the outlook or downgrade any of these ratings, particularly to below investment grade, borrowing cost on new issuances would increase, which would diminish financial results, and the potential pool of investors and funding sources could decrease.

In 2011, one rating agency downgraded both the short-term and senior unsecured long-term debt of SCANA. In 2013, another rating agency revised the outlook for SCANA and its subsidiaries to negative from stable. These downgrades and lowered outlook have increased the short-term borrowing rates of SCANA and may have the effect of increasing the long-term borrowing rates of SCANA and SCE&G. Although access to the short-term market has not been adversely impacted, this could change under different market conditions.

SCANA's leverage ratio of long- and short-term debt to capital was approximately 56% at December 31, 2013. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA's ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company's debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its ability to access the capital markets may be impaired.

Operating results may be adversely affected by natural disasters, man-made mishaps and abnormal weather.

The Company has delivered less gas and received lower prices for natural gas in deregulated markets when weather conditions have been milder than normal, and as a consequence earned less income from those operations. During 2010, the SCPSC approved SCE&G's implementation of an eWNA on a pilot basis; it was discontinued at the end of 2013. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Company and Consolidated SCE&G. Hot or cold weather could result in higher bills for customers and result in higher write-offs of receivables and in a greater number of disconnections for non-payment. In addition, for the Company and Consolidated SCE&G, severe weather can be destructive, causing outages and property damage, adversely affecting operating expenses and revenues.

Natural disasters (such as electromagnetic events and the 2011 earthquake and tsunami in Japan) or man-made mishaps (such as the San Bruno, California natural gas transmission pipeline failure, the Kingston, Tennessee coal ash pond failure, and cyber-security failures experienced by many businesses) could have direct significant impacts on the Company and Consolidated SCE&G and on our key contractors and suppliers or could indirectly impact us through changes to federal, state or local policies, laws and regulations, and have a significant impact on our financial position, operating expenses, and cash flows.

Potential competitive changes may adversely affect our gas and electricity businesses due to the loss of customers, reductions in revenues, or write-down of stranded assets.

The utility industry has been undergoing structural change for a number of years, resulting in increasing competitive pressures on electric and natural gas utility companies. Competition in wholesale power sales via a RTO/ISO (Regional Transmission Organization/Independent System Operator) is in effect across much of the country, but the Southeastern utilities have retained the traditional bundled, vertically integrated structure. Should a RTO/ISO-market be implemented in the Southeast, potential risks emerge from reliance on volatile wholesale market prices as well as increased costs associated with new delivery transmission and distribution infrastructure.

Some states have also mandated or encouraged unbundled retail competition. Should this occur in South Carolina, increased competition may create greater risks to the stability of utility earnings generally and may in the future reduce earnings from retail electric and natural gas sales. In a deregulated environment, formerly regulated utility companies that are not responsive to a competitive energy marketplace may suffer erosion in market share, revenues and profits as competitors gain access to their customers. In addition, the Company's and Consolidated SCE&G's generation assets would be exposed to considerable financial risk in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, a write-down in the value of the related assets would be required.

The Company and Consolidated SCE&G are subject to the risk of loss of sales due to the growth of distributed generation especially in the form of renewable power such as solar photovoltaic systems. As a result of federal and state subsidies and potential regulations allowing third-party retail sales, the growth of such distributed generation could be significant in the future. Such growth will lessen Company and Consolidated SCE&G sales and slow growth, potentially causing higher rates to customers.

The Company and SCE&G are subject to risks associated with changes in business and economic climate which could adversely affect revenues, results of operations, cash flows and financial condition and could limit access to capital.

Sales, sales growth and customer usage patterns are dependent upon the economic climate in the service territories of the Company and SCE&G, which may be affected by regional, national or even international economic factors. Some economic sectors important to our customer base may be particularly affected. Adverse events, economic or otherwise, may also affect the operations of suppliers and key customers. Such events may result in the loss of suppliers or customers, in costs charged by suppliers, in changes to customer usage patterns and in the failure of customers to make timely payments to us. With respect to the Company, such events also could adversely impact the results of operations through the recording of a goodwill or other asset impairment. The success of local and state governments in attracting new industry to our service territories is important to our sales and growth in sales, as are stable levels of taxation (including property, income or other taxes) which may be affected by local, state, or federal budget deficits, adverse economic climates generally or legislative or regulatory actions. Budget cutbacks also adversely affect funding levels of federal and state support agencies and non-profit organizations that assist low income customers with bill payments.

In addition, conservation and demand side management efforts and/or technological advances may cause or enable customers to significantly reduce their usage of the Company's and SCE&G's products and adversely affect sales, sales growth, and customer usage patterns.

Factors that generally could affect our ability to access capital include economic conditions and our capital structure. Much of our business is capital intensive, and achievement of our capital plan and long-term growth targets is dependent, at least in part, upon our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition and future results of operations could be significantly harmed.

Problems with operations could cause us to curtail or limit our ability to serve customers or cause us to incur substantial costs, thereby adversely impacting revenues, results of operations, cash flows and financial condition.

Critical processes or systems in the Company's or Consolidated SCE&G's operations could become impaired or fail from a variety of causes, such as equipment breakdown, transmission line failure, information systems failure or security breach, the effects of drought (including reduced water levels) on the operation of emission control or other generation equipment, and the effects of a pandemic or terrorist attack on our workforce or facilities or on the ability of vendors and suppliers to maintain services key to our operations.

In particular, as the operator of power generation facilities, many of which entered service prior to 1985 and may be difficult to maintain, Consolidated SCE&G could incur problems, such as the breakdown or failure of power generation or emission control equipment, transmission equipment, or other equipment or processes which would result in performance below assumed levels of output or efficiency. The operation of the New Units may entail additional cycling of our coal-fired generation facilities and may thereby increase the number of unplanned outages at those facilities. In addition, any such breakdown or failure may result in Consolidated SCE&G purchasing emission allowances or replacement power at market rates, if such allowances and replacement power are available at all. These purchases are subject to state regulatory prudency reviews for recovery through rates. If replacement power is not available, such problems could result in interruptions of service (blackout or brownout conditions) in all or part of SCE&G's territory or elsewhere in the region. Similarly, a gas transmission or distribution line failure of the Company or Consolidated SCE&G could affect the safety of the public, destroy property, and interrupt our ability to serve customers.

Events such as these could entail substantial repair costs, litigation, fines and penalties, and damage to reputation, each of which could have an adverse effect on the Company's revenues, results of operations, and financial condition. Insurance may not be available or adequate to respond to these events.

A failure of the Company to maintain the physical and cyber security of its operations may result in the failure of operations, damage to equipment, or loss of information, and could result in a significant adverse impact to the Company's financial position, results of operations and cash flows.

The Company depends on maintaining the physical and cyber security of its operations and assets. As much of our business is part of the nation's critical infrastructure, the loss or impairment of the assets associated with that portion of our business could have serious adverse impacts on the customers and communities that we serve. Virtually all of the Company's operations are dependent in some manner upon our cyber systems, which encompass electric and gas transmission and distribution operations, nuclear and fossil fuel generating plants, human resource and customer systems and databases, information system networks, and systems containing confidential corporate information. Cyber systems, such as those of the Company, are often targets of malicious cyber attacks. A successful physical or cyber attack could lead to outages, failure of operations of all or portions of our businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information. The Company may not be readily able to recover from such events. In addition, the failure to secure our operations from such physical and cyber events may cause us reputational damage. Litigation, penalties and claims from a number of parties, including customers, regulators and shareholders, may ensue. Insurance may not be adequate to respond to these events. As a result, the Company's financial position, results of operations, and cash flows may be adversely affected.

SCANA’s ability to pay dividends and to make payments on SCANA’s debt securities may be limited by covenants in certain financial instruments and by the financial results and condition of its subsidiaries, thereby adversely impacting the valuation of our common stock and our access to capital .

We are a holding company that conducts substantially all of our operations through our subsidiaries. Our assets consist primarily of investments in subsidiaries. Therefore, our ability to meet our obligations for payment of interest and principal on outstanding debt and to pay dividends to shareholders and corporate expenses depends on the earnings, cash flows, financial condition and capital requirements of our subsidiaries, and the ability of our subsidiaries, principally Consolidated SCE&G, PSNC Energy and SEMI, to pay dividends or to repay funds to us. Our ability to pay dividends on our common stock may also be limited by existing or future covenants limiting the right of our subsidiaries to pay dividends on their common stock. Any significant reduction in our payment of dividends in the future may result in a decline in the value of our common stock. Such a decline in value could limit our ability to raise debt and equity capital.

A significant portion of Consolidated SCE&G’s generating capacity is derived from nuclear power, the use of which exposes us to regulatory, environmental and business risks. These risks could increase our costs or otherwise constrain our business, thereby adversely impacting our results of operations, cash flows and financial condition. These risks will increase as the New Units are developed.

In 2013, Summer Station Unit 1, operated by SCE&G, provided approximately 5.6 million MWh, or 24% of our generation. When the New Units are completed, our generating capacity and the percentage of total generating capacity represented by nuclear sources are expected to increase. Hence, SCE&G is subject to various risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling and disposal of radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations or those of others in the United States;
- The possibility that new laws and regulations could be enacted that could adversely affect the liability structure that currently exists in the United States;
- Uncertainties with respect to procurement of nuclear fuel and the storage of spent nuclear fuel;
- Uncertainties with respect to contingencies if insurance coverage is inadequate; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their operating lives.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident, if a major incident should occur at a domestic nuclear facility, it could harm our results of operations, cash flows and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Finally, in today’s environment, there is a heightened risk of terrorist attack on the nation’s nuclear facilities, which has resulted in increased security costs at our nuclear plant.

Failure to retain and attract key personnel could adversely affect the Company’s and Consolidated SCE&G’s operations and financial performance.

As with many other utilities, a significant portion of our workforce will be eligible for retirement during the next few years. We must attract, retain and develop executive officers and other professional, technical and craft employees with the skills and experience necessary to successfully manage, operate and grow our business. Competition for these employees is

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high, and in some cases we must compete for these employees on a regional or national basis. We may be unable to attract and retain these personnel. Further, the Company’s or Consolidated SCE&G’s ability to construct or maintain generation or other assets requires the availability of suitable skilled contractor personnel. We may be unable to obtain appropriate contractor personnel at the times and places needed. Labor disputes with employees or contractors covered by collective bargaining agreements also could adversely affect implementation of our strategic plan and our operational and financial performance.

The Company and Consolidated SCE&G are subject to the risk that strategic decisions made by us either do not result in a return of or on invested capital or might negatively impact our competitive position, which can adversely impact our results of operations, cash flows, financial position, and access to capital.

From time to time, the Company and Consolidated SCE&G make strategic decisions that may impact our direction with regard to business opportunities, the services and technologies offered to customers or that are used to serve customers, and the generating plants and other infrastructure that form the basis of much of our business. These strategic decisions may not result in a return of or on our invested capital, and the effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators), to the detriment of the Company or Consolidated SCE&G. Over time, these strategic decisions or changing attitudes toward such decisions, which could be adverse to the Company’s or Consolidated SCE&G’s interests, may have a negative effect on our results of operations, cash flows and financial position, as well as limit our ability to access capital.

The Company and Consolidated SCE&G are subject to the reputational risks that may result from a failure to adhere to high standards of compliance with laws and regulations, ethical conduct, operational effectiveness, and safety of employees, customers and the public. These risks could adversely affect the valuation of our common stock and the Company’s and Consolidated SCE&G’s access to capital.

The Company and Consolidated SCE&G are committed to comply with all laws and regulations, to focus on the safety of employees, customers and the public, to maintain the privacy of information related to our customers and employees and to maintain effective communications with the public and key stakeholder groups, particularly during emergencies and times of crisis. The Company and Consolidated SCE&G also are committed to operational excellence and, through our Code of Conduct and Ethics, to maintain high standards of ethical conduct in our business operations. A failure to meet these commitments may subject the Company and Consolidated SCE&G not only to fraud, litigation and financial loss, but also to reputational risk that could adversely affect the valuation of SCANA’s stock, adversely affect the Company’s and Consolidated SCE&G’s access to capital, and result in further regulatory oversight. Insurance may not be available or adequate to respond to these events.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable

ITEM 2. PROPERTIES

SCANA owns no significant property other than the capital stock of each of its subsidiaries. It holds, directly or indirectly, all of the capital stock of each of its subsidiaries.
SCE&G's bond indenture, securing the First Mortgage Bonds issued thereunder, constitutes a direct mortgage lien on substantially all of its electric utility property. GENCO's Williams Station is also subject to a first mortgage lien which

secures certain outstanding debt of GENCO.
ELECTRIC PROPERTIES

The following table shows the electric generating facilities and their net generating capacity as of December 31, 2013.

	In-Service Date	Net Generating Capacity Summer (MW)	
Coal-Fired Steam:			
McMeekin - Near Irmo, SC	1958	250	*
Wateree - Eastover, SC	1970	684	
Williams - Goose Creek, SC	1973	605	
Cope - Cope, SC	1996	415	
Kapstone - Charleston, SC	1999	85	
Gas-Fired Steam - Urquhart Unit 3 - Beech Island, SC	1953	95	*
Nuclear - V. C. Summer - Parr, SC (reflects SCE&G's 66.7% ownership share)	1984	647	
Internal Combustion Turbines:			
Peaking units - various locations in SC	1968-1999	352	
Urquhart Combined Cycle - Beech Island, SC	2002	458	
Jasper Combined Cycle - Jasper, SC	2004	852	
Hydro:			
Saluda - Irmo, SC	1930	200	
Other hydro units - various locations in or bordering SC	1905-1914	18	
Fairfield Pumped Storage - Parr, SC	1978	576	

* As described in Note 2 to the consolidated financial statements for SCANA and SCE&G, under plans announced in 2012, SCE&G has retired or intends to retire six coal-fired units with an aggregate net generating capacity (summer rating) of 730 MW by 2018, subject to future developments in environmental regulations, among other matters. As of December 31, 2013, three of these units had been retired (with an aggregate net generating capacity, summer rating, of 385 MW) and are not included in the table above. Another unit, Urquhart Unit 3, was fueled with coal prior to 2013, and is expected to be fueled with natural gas until its retirement in 2018.

SCE&G owns 436 substations having an aggregate transformer capacity of 30 million KVA. The transmission system consists of 3,307 miles of lines, and the distribution system consists of 18,397 pole miles of overhead lines and 7,004 trench miles of underground lines.

NATURAL GAS DISTRIBUTION AND TRANSMISSION PROPERTIES

SCE&G's natural gas system includes 448 miles of transmission pipeline of up to 20 inches in diameter that connect its distribution system with Southern Natural, Transco and CGT. SCE&G’s distribution system consists of 16,450 miles of distribution mains and related service facilities. SCE&G also owns two LNG plants, one located near Charleston, South Carolina, and the other in Salley, South Carolina. The Charleston facility can liquefy up to 6 MMCF per day and store the liquefied equivalent of 980 MMCF of natural gas. The Salley facility can store the liquefied equivalent of 900 MMCF of natural gas and has no liquefying capabilities. The LNG facilities have the capacity to regasify approximately 60 MMCF per day at Charleston and 90 MMCF per day at Salley.

CGT's natural gas system consists of 1,469 miles of transmission pipeline of up to 24 inches in diameter. CGT's system transports gas to its customers from the transmission systems of Southern Natural at Port Wentworth, Georgia and Aiken County, South Carolina, Southern LNG, Inc. at Elba Island, near Savannah, Georgia and Transco in Cherokee and Spartanburg counties in South Carolina.

PSNC Energy's natural gas system consists of 594 miles of transmission pipeline of up to 24 inches in diameter that connect its distribution systems with Transco. PSNC Energy's distribution system consists of 20,411 miles of distribution mains and related service facilities. PSNC Energy owns one LNG plant with storage capacity of 1,000 MMCF, the capacity to liquefy up to 4 MMCF per day and the capacity to regasify approximately 100 MMCF per day. PSNC Energy also owns, through a wholly-owned subsidiary, 33.21% of Cardinal Pipeline Company, LLC, which owns a 105-mile transmission pipeline in North Carolina. In addition, PSNC Energy owns, through a wholly-owned subsidiary, 17% of Pine Needle LNG Company, LLC. Pine Needle owns and operates a liquefaction, storage and regasification facility in North Carolina.

ITEM 3. LEGAL PROCEEDINGS

SCANA and SCE&G are engaged in various claims and litigation incidental to their business operations which management anticipates will be resolved without a material impact on their respective results of operations, cash flows or financial condition. In addition, certain material regulatory and environmental matters and uncertainties, some of which remain outstanding at December 31, 2013, are described in the Rate Matters section of Note 2 and in the Environmental section of Note 10 to the consolidated financial statements of SCANA and SCE&G.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

EXECUTIVE OFFICERS OF SCANA CORPORATION

The executive officers are elected at the annual meeting of the Board of Directors, held immediately after the annual meeting of shareholders, and hold office until the next such annual meeting, unless (1) a resignation is submitted, (2) the Board of Directors shall otherwise determine or (3) as provided in the By-laws of SCANA. Positions held are for SCANA and all subsidiaries unless otherwise indicated.

Name	Age	Positions Held During Past Five Years	Dates
Kevin B. Marsh	58	Chairman of the Board and Chief Executive Officer President and Chief Operating Officer-SCANA President and Chief Operating Officer-SCE&G	2011-present 2011-present *-2011
Jimmy E. Addison	53	Executive Vice President Chief Financial Officer Senior Vice President	2012-present *-present *-2012
Jeffrey B. Archie	56	Senior Vice President and Chief Nuclear Officer-SCE&G Senior Vice President-SCANA Vice President of Nuclear Operations-SCE&G	2009-present 2010-present *-2009
George J. Bullwinkel	65	President and Chief Operating Officer-SEMI, SCI and ServiceCare Senior Vice President-SCANA	*-present *-present
Sarena D. Burch	56	Senior Vice President-Fuel Procurement and Asset Management-SCE&G and PSNC Energy Senior Vice President-SCANA	*-present *-present
Stephen A. Byrne	54	President of Generation and Transmission and Chief Operating Officer-SCE&G Executive Vice President-SCANA Executive Vice President-Generation and Transmission -SCE&G Executive Vice President-Generation, Nuclear and Fossil Hydro-SCE&G Senior Vice President-Generation, Nuclear and Fossil Hydro-SCE&G	2011-present 2009-present 2011 2009-2011 *-2009
Paul V. Fant	60	President and Chief Operating Officer-CGT Senior Vice President-SCANA	*-present *-present
D. Russell Harris	49	President of Gas Operations-SCE&G President and Chief Operating Officer-PSNC Energy Senior Vice President-Gas Distribution-SCANA Senior Vice President-SCANA	2013-present *-present 2013-present 2012-2013
W. Keller Kissam	47	President of Retail Operations-SCE&G Senior Vice President-SCANA Senior Vice President-Retail Electric-SCE&G Vice President-Electric Operations-SCE&G	2011-present 2011-present 2011 *-2011
Ronald T. Lindsay	63	Senior Vice President, General Counsel and Assistant Secretary	*-present
Charles B. McFadden	69	Senior Vice President-Governmental Affairs and Economic Development-	*-present

		SCANA Services	*-present
		Senior Vice President-SCANA	
Martin K. Phalen	59	Senior Vice President-Administration-SCANA	2012-present
		Vice President-Gas Operations-SCE&G	*-2012

* Indicates position held at least since March 1, 2009.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

COMMON STOCK INFORMATION

SCANA Corporation:

Price Range (NYSE Composite Listing):

	2013				2012			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.	4th Qtr.	3rd Qtr.	2nd Qtr.	1st Qtr.
High	$48.15	$52.93	$54.41	$51.23	$49.64	$50.34	$48.24	$46.12
Low	$44.75	$45.72	$47.22	$45.57	$44.71	$47.18	$43.32	$43.56

SCANA common stock trades on the NYSE using the ticker symbol SCG. Newspaper stock listings use the name SCANA. At February 20, 2014 there were 141,144,841 shares of SCANA common stock outstanding which were held by approximately 28,121 shareholders of record. For a summary of equity securities issuable under SCANA's compensation plans at December 31, 2013, see Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

SCANA declared quarterly dividends on its common stock of $.5075 per share in 2013 and $.495 per share in 2012. On February 20, 2014, SCANA increased the quarterly cash dividend rate on SCANA common stock to $.525 per share, an increase of approximately 3.5%. The next quarterly dividend is payable April 1, 2014 to shareholders of record on March 10, 2014. For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCANA.

SCE&G:

All of SCE&G's common stock is owned by SCANA, and no established public trading market exists for SCE&G common stock. During 2013 and 2012, SCE&G declared quarterly dividends on its common stock in the following amounts:

Declaration Date	Amount		Declaration Date	Amount	
February 15, 2012	$51.6	million	February 20, 2013	$62.2	million
May 3, 2012	52.3	million	April 25, 2013	62.0	million
August 2, 2012	54.0	million	July 31, 2013	65.8	million
October 24, 2012	44.3	million	October 31, 2013	60.0	million

On February 20, 2014, SCE&G declared dividends on its common stock of $62.5 million.

For a discussion of provisions that could limit the payment of cash dividends, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS under Liquidity and Capital Resources-Financing Limits and Related Matters and Note 3 to the consolidated financial statements for SCE&G.

ITEM 6. SELECTED FINANCIAL DATA

As of or for the Year Ended December 31,	2013	2012	2011	2010	2009
	(Millions of dollars, except statistics and per share amounts)				
SCANA:					
Statement of Income Data					
Operating Revenues	$4,495	$4,176	$4,409	$4,601	$4,237
Operating Income	$910	$859	$813	$768	$699
Preferred Stock Dividends	$—	$—	$—	$—	$9
Income Available to Common Shareholders	$471	$420	$387	$376	$348
Common Stock Data					
Weighted Average Common Shares Outstanding (Millions)	138.7	131.1	128.8	125.7	122.1
Basic Earnings Per Share	$3.40	$3.20	$3.01	$2.99	$2.85
Diluted Earnings Per Share	$3.39	$3.15	$2.97	$2.98	$2.85
Dividends Declared Per Share of Common Stock	$2.03	$1.98	$1.94	$1.90	$1.88
Balance Sheet Data					
Utility Plant, Net	$11,643	$10,896	$10,047	$9,662	$9,009
Total Assets	$15,164	$14,616	$13,534	$12,968	$12,094
Total Equity	$4,664	$4,154	$3,889	$3,702	$3,408
Short-term and Long-term Debt	$5,825	$5,744	$5,306	$4,909	$4,846
Other Statistics					
Electric:					
Customers (Year-End)	678,273	669,966	664,196	660,580	654,766
Total sales (Million kWh)	22,313	23,879	24,188	24,884	23,104
Generating capability-Net MW (Year-End)	5,237	5,533	5,642	5,645	5,611
Territorial peak demand-Net MW	4,574	4,761	4,885	4,735	4,557
Regulated Gas:					
Customers, excluding transportation (Year-End)	837,232	818,983	803,644	794,841	782,192
Sales, excluding transportation (Thousand Therms)	921,533	798,978	812,416	931,879	832,931
Transportation customers (Year-End)	496	499	492	491	482
Transportation volumes (Thousand Therms)	1,729,399	1,559,542	1,585,202	1,546,234	1,388,096
Retail Gas Marketing:					
Retail customers (Year-End)	454,104	449,144	455,258	464,123	455,198
Firm customer deliveries (Thousand Therms)	382,728	310,442	341,554	402,583	347,324
Nonregulated interruptible customer deliveries (Thousand Therms)	1,928,266	1,981,085	1,845,327	1,728,161	1,628,942
SCE&G:					
Statement of Income Data					
Operating Revenues	$2,845	$2,809	$2,819	$2,815	$2,569
Operating Income	$737	$717	$654	$604	$547
Net Income	$391	$352	$316	$304	$288
Net Income Attributable to Noncontrolling Interest	$11	$11	$10	$14	$7
Preferred Stock Dividends	$—	$—	$—	$—	$9
Earnings Available to Common Shareholder	$380	$341	$306	$290	$272
Balance Sheet Data					
Utility Plant, Net	$10,048	$9,375	$8,588	$8,198	$7,595
Total Assets	$12,700	$12,104	$11,037	$10,574	$9,813
Total Equity	$4,489	$4,043	$3,773	$3,541	$3,259

Short-term and Long-term Debt	$4,306	$4,171	$3,753	$3,440	$3,430
Other Statistics					
Electric:					
Customers (Year-End)	678,338	670,030	664,273	660,642	654,830
Total sales (Million kWh)	22,327	23,899	24,200	24,887	23,107
Generating capability-Net MW (Year-End)	5,237	5,533	5,642	5,645	5,611
Territorial peak demand-Net MW	4,574	4,761	4,885	4,735	4,557
Regulated Gas:					
Customers, excluding transportation (Year-End)	329,179	322,419	316,683	313,346	309,687
Sales, excluding transportation (Thousand Therms)	457,119	412,163	407,073	447,057	399,752
Transportation customers (Year-End)	173	166	155	148	130
Transportation volumes (Thousand Therms)	155,190	260,215	192,492	190,931	217,750

SCANA CORPORATION

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

OVERVIEW

SCANA, through its wholly-owned regulated subsidiaries, is primarily engaged in the generation, transmission, distribution and sale of electricity in parts of South Carolina and in the purchase, transmission and sale of natural gas in portions of North Carolina and South Carolina. Through a wholly-owned nonregulated subsidiary, SCANA markets natural gas to retail customers in Georgia and to wholesale customers primarily in the southeast. Other wholly-owned nonregulated subsidiaries provide fiber optic and other telecommunications services and provide service contracts on certain home appliances and heating and air conditioning units. A service company subsidiary of SCANA provides administrative, management and other services to SCANA and its subsidiaries.

The following map indicates areas where the Company's significant business segments conduct their activities, as further described in this overview section.

The following percentages reflect revenues and net income earned by the Company's regulated and nonregulated businesses (including the holding company) and the percentage of total assets held by them.

	2013	2012	2011
Revenues			
Regulated	75 %	77 %	74 %
Nonregulated	25 %	23 %	26 %
Net Income			
Regulated	97 %	99 %	97 %
Nonregulated	3 %	1 %	3 %
Assets			
Regulated	95 %	95 %	94 %
Nonregulated	5 %	5 %	6 %

Key Earnings Drivers and Outlook

During 2013, economic growth continued to improve in the southeast. Significant industrial announcements were made in the Company's South Carolina and North Carolina service territories during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 5.7% over 2012. Residential and commercial customer growth rates in the Company's regulated businesses also remained positive. Unemployment rates for the states in which the Company primarily provides service also improved in 2013, though such rates improved in part due to people leaving the workforce. Nationwide, the civilian labor force participation rate was 62.8% at December 31, 2013, matching a 35-year low.

Unemployment (seasonally adjusted)	United States	Georgia	North Carolina	South Carolina
December 31, 2013 (preliminary)	6.7%	7.4%	6.9%	6.6%
December 31, 2012	7.8%	8.7%	9.4%	8.6%
December 31, 2011	8.9%	9.4%	10.4%	9.6%

Over the next five years, key earnings drivers for the Company will be additions to rate base at its regulated subsidiaries, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage in each of the regulated utility businesses, earnings in the natural gas marketing business in Georgia and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina. At December 31, 2013, SCE&G provided electricity to approximately 678,000 customers in an area covering nearly 17,000 square miles. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results for electric operations are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Through 2013, the effect of weather on operating results was largely mitigated by the eWNA; however, the eWNA was discontinued pursuant to SCPSC order effective with the first billing cycle of January 2014. Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G's allowed return on equity in 2013 was 10.25% for non-BLRA expenditures, and 11.0% for BLRA-related expenditures. As further described in Note 2 to the consolidated financial statements, SCE&G's allowed return on equity for non-BLRA expenditures was 10.7% prior to 2013. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (2012 summer rating) of 730 MW. As of December 31, 2013, three of these units have been retired. For additional information, see Note 1 and Note 2 to the consolidated financial statements.

New Nuclear Construction

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final

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two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

SCE&G expects Unit 2 to be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest.

Significant recent developments in new nuclear construction include the following:

- In the first quarter of 2013, initial pouring of the Unit 2 nuclear island basemat was completed. The basemat provides a foundation for the containment vessel, shield building and auxiliary building that make up the nuclear island. The Unit 3 nuclear island basemat was completed in the fourth quarter of 2013.

- In April 2013, the 500-ton CR-10 module was set on the Unit 2 basemat. CR-10 supports the containment vessel. Construction of Unit 3's CR-10 module is currently underway.

- In May 2013, the containment vessel bottom head for Unit 2 was put in place. The containment vessel will house numerous reactor system components, such as the reactor vessel, steam generator and pressurizer. Work continues in building containment vessel rings that will be placed on the containment vessel bottom head for Unit 2.

- In September 2013, the reactor vessel cavity for Unit 2 (CA-04 module) was placed in the containment vessel bottom head. The reactor vessel cavity will house the reactor vessel, which in turn will house the fuel assemblies. The reactor vessel for Unit 2 is on-site.

- Fabrication has begun for Unit 2's steam generator and refueling canal module (CA-01 module) that will be located inside the containment vessel.

- Ring 1 of the Unit 2 containment vessel is scheduled to be placed on the containment vessel bottom head in the second quarter 2014. Ring 2 is scheduled to be placed in the fourth quarter of 2014.

- While progress has been made with production, quality assurance and quality control issues, the schedule for fabrication of sub-modules at the contractor facility remains a focus area for the project.

- During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

Environmental

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. New federal effluent limitation guidelines for steam electric generating units were published in the Federal Register on

June 7, 2013, and the ELG Rule is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, and Congress is expected to consider further amendments to the CWA.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 14, 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO.

The above environmental initiatives and other similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, the Company cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on the Company, if any. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The gas distribution segment, comprised of the local distribution operations of SCE&G and PSNC Energy, is primarily engaged in the purchase, transportation and sale of natural gas to retail customers in portions of South Carolina and North Carolina. At December 31, 2013 this segment provided natural gas to approximately 838,000 customers in areas covering 34,600 square miles.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25% for SCE&G and 10.60% for PSNC Energy.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact the Company’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States has resulted in significantly lower prices for this commodity, and such prices are expected to continue for the foreseeable future.

Retail Gas Marketing

SCANA Energy, a division of SEMI, comprises the retail gas marketing segment. This segment markets natural gas to approximately 454,000 customers throughout Georgia (as of December 31, 2013, and includes approximately 68,000 customers in its regulated division described below). SCANA Energy’s total customer base represents an approximate 30% share of the customers in Georgia’s deregulated natural gas market. SCANA Energy remains the second largest natural gas marketer in the state. SCANA Energy’s competitors include an affiliate of a large energy company with experience in Georgia’s energy market, as well as several electric membership cooperatives. SCANA Energy’s ability to maintain its market share depends on the prices it charges customers relative to the prices charged by its competitors, its ability to continue to provide high levels of customer service and other factors. In addition, SCANA Energy's operating results are highly sensitive to weather. This market has matured in the last decade, resulting in lower margins and enhanced competition for customers.

As Georgia’s regulated provider, SCANA Energy provides service at rates approved by the GPSC to low-income customers and to customers unable to obtain or maintain natural gas service from other marketers . SCANA Energy receives funding from Georgia's Universal Service Fund to offset some of the bad debt associated with the low-income group. In third quarter 2013, SCANA Energy’s contract to serve as Georgia’s regulated provider of natural gas was extended by the GPSC through August 31, 2015. SCANA Energy files financial and other information periodically with the GPSC, and such information is available at www.psc.state.ga.us (which is not intended as an active hyperlink; the information on the GPSC website is not part of this or any other report filed with the SEC).

SCANA Energy and certain of SCANA's other natural gas distribution and marketing segments maintain gas inventory and utilize forward contracts and other financial instruments, including commodity swaps and futures contracts, to manage their exposure to fluctuating commodity natural gas prices. See Note 6 to the consolidated financial statements. As a part of this risk management process, at any given time, a portion of SCANA's projected natural gas needs has been purchased or otherwise placed under contract. Since SCANA Energy operates in a competitive market, it may be unable to sustain its current levels of customers and/or pricing, thereby reducing expected margins and profitability. Further, there can be no assurance that Georgia's gas delivery regulatory framework will remain unchanged as dynamic market conditions evolve.

Energy Marketing

The divisions of SEMI excluding SCANA Energy comprise the energy marketing segment. This segment markets natural gas primarily in the southeast and provides energy-related risk management services to customers. The operating results for energy marketing are primarily influenced by customer demand for natural gas and the ability to control growth of costs. Demand for natural gas is primarily affected by the price of alternate fuels and customer growth. In addition, certain pipeline capacity available for Energy Marketing to serve industrial and other customers is dependent upon the market share held by SCANA Energy in the retail market.

RESULTS OF OPERATIONS

	2013	2012	2011
Basic earnings per share	$3.40	$3.20	$3.01
Diluted earnings per share	$3.39	$3.15	$2.97
Cash dividends declared (per share)	$2.03	$1.98	$1.94

2013 vs 2012	Basic earnings per share increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.
2012 vs 2011	Basic earnings per share increased due to higher electric and gas margins and gains on sales of communications towers. These increases were partially offset by higher operating expenses, higher depreciation expense, higher property taxes, dilution from additional shares outstanding and higher interest expense, as further described below.

Diluted earnings per share figures give effect to dilutive potential common stock using the treasury stock method. See Note 1 to the consolidated financial statements.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$2,430.5	(0.9)%	$2,453.1	0.9%	$2,432.2
Less: Fuel used in generation	751.0	(11.0)%	844.2	(8.5)%	922.5
Purchased power	43.0	53.0%	28.1	46.4%	19.2
Margin	$1,636.5	3.5%	$1,580.8	6.1%	$1,490.5

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2013 vs 2012	Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.
2012 vs 2011	Margin increased primarily by $54.4 million due to an increase in retail electric base rates approved by the SCPSC under the BLRA, by $3.7 million due to customer growth and by $11.0 million due to the expiration of a decrement rider approved in the 2010 retail electric base rate case.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2013	Change	2012	Change	2011
Residential	7,571	—	7,571	(8.0)%	8,232
Commercial	7,205	(1.2)%	7,291	(1.4)%	7,397
Industrial	6,000	2.8%	5,836	(1.7)%	5,938
Other	581	(0.9)%	586	2.4%	572
Total retail sales	21,357	0.3%	21,284	(3.9)%	22,139
Wholesale	955	(63.2)%	2,595	26.6%	2,049
Total Sales	22,312	(6.6)%	23,879	(1.3)%	24,188

2013 vs 2012	Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.
2012 vs 2011	Retail sales volume decreased by 983 GWh primarily due to the effects of milder weather. The increase in wholesale sales is primarily due to higher contract utilization by a wholesale customer.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy. Gas Distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$942.6	23.2%	$765.0	(9.0)%	$840.4
Less: Gas purchased for resale	534.9	42.8%	374.6	(19.7)%	466.3
Margin	$407.7	4.4%	$390.4	4.4%	$374.1

2013 vs 2012	Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth and increased industrial usage.
2012 vs 2011	Margin at SCE&G increased by $8.3 million due to the SCPSC-approved increases in retail gas base rates under the RSA which became effective with the first billing cycles of November 2011 and 2012. Margin at PSNC Energy increased by $5.1 million primarily due to residential and commercial customer growth and increased industrial sales due to the competitive price of gas versus alternate fuel sources.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2013	Change	2012	Change	2011
Residential	41,268	24.4 %	33,161	(9.3)%	36,568
Commercial	28,181	12.7 %	25,001	(3.0)%	25,772
Industrial	22,319	4.6 %	21,340	13.6 %	18,782
Transportation gas	42,221	9.0 %	38,736	13.4 %	34,152
Total	133,989	13.3 %	118,238	2.6 %	115,274

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

2012 vs 2011 Residential and commercial sales volume decreased primarily due to milder weather. Industrial and transportation sales volumes increased due to the competitive price of gas versus alternate fuel sources.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy which operates in Georgia's natural gas market. Retail Gas Marketing revenues and net income were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$465.2	12.8 %	$412.5	(13.8)%	$478.8
Net Income	23.8	*	10.5	(56.6)%	24.2

* Greater than 100%

2013 vs 2012 Changes in operating revenues and net income are due to higher demand in 2013 primarily as a result of milder weather in 2012.

2012 vs 2011 Reductions in operating revenues and net income were primarily due to milder weather and a decrease in the number of customers served under the regulated provider program in 2012.

Energy Marketing

Energy Marketing is comprised of the Company's nonregulated marketing operations, excluding SCANA Energy. Energy Marketing operating revenues and net income were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$818.5	22.3 %	$669.0	(20.8)%	$844.9
Net Income	6.1	13.0 %	5.4	22.7 %	4.4

2013 vs 2012 Operating revenues and net income increased due to higher industrial sales volume and higher market prices.

2012 vs 2011 Operating revenues decreased due to lower market prices. Net income increased due to higher consumption.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other operation and maintenance	$707.5	2.6 %	$689.3	4.8 %	$657.9
Depreciation and amortization	378.1	6.2 %	356.1	2.8 %	346.3
Other taxes	219.7	6.1 %	207.1	3.1 %	200.8

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2013 vs 2012	Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.
2012 vs 2011	Other operation and maintenance expenses increased by $9.3 million due to higher generation, transmission and distribution expenses and by $25.0 million due to higher incentive compensation and other benefits. These increases were partially offset by $3.9 million due to lower customer service expenses, including bad debt expense, and by $1.6 million due to lower general expenses. Depreciation and amortization expense increased primarily due to net property additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on the Company's income statements and balance sheets as follows:

Millions of dollars	2013	Change		2012	Change		2011
Income Statement Impact:							
Employee benefit costs	$15.5	*		$4.0	53.8	%	$2.6
Other expense	1.0	25.0	%	0.8	60.0	%	0.5
Balance Sheet Impact:							
Increase in capital expenditures	7.2	9.1	%	6.6	69.2	%	3.9
Component of amount receivable from Summer Station co-owner	2.5	13.6	%	2.2	83.3	%	1.2
Increase in regulatory asset	5.5	(63.1	)%	14.9	63.7	%	9.1
Net periodic benefit cost	$31.7	11.2	%	$28.5	64.7	%	$17.3

* Greater than 100%

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension cost related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension costs related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2 to the consolidated financial statements). In 2013, such amortizations totaled approximately $2.0 million for electric operations and $0.2 million for gas operations.

Other Income (Expense)

Other income (expense) includes the results of certain incidental activities of regulated subsidiaries and the activities of certain non-regulated subsidiaries. Components of other income (expense) were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other income	$100.3	71.2 %	$58.6	12.3 %	$52.2
Other expense	(45.5)	8.1 %	(42.1)	5.3 %	(40.0)
Total	$54.8	*	$16.5	35.2 %	$12.2

* Greater than 100%

2013 vs 2012	Changes in other income were primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income. This increase in other income was partially offset by the sales of communications towers that were recorded in 2012 by a non-regulated subsidiary. Changes in other expense were not significant.
2012 vs 2011	Changes in other income were primarily due to the sales of communications towers in 2012 by a non-regulated subsidiary. Changes in other expense were not significant.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. The Company includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 5.8% of income before income taxes in 2013, 5.4% in 2012 and 3.9% in 2011.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Interest on long-term debt, net	$292.8	0.9 %	$290.2	4.9 %	$276.6
Other interest expense	4.6	(11.5)%	5.2	(32.5)%	7.7
Total	$297.4	0.7 %	$295.4	3.9 %	$284.3

Interest on long-term debt increased in each year primarily due to increased long-term borrowings. Other interest expense decreased in 2013 and 2012, primarily due to reductions in principal balances outstanding on short-term debt over the respective prior year and also decreased due to the reversal in 2012 of interest which had been accrued in 2011 related to a tax uncertainty that was resolved (see Note 5 to the consolidated financial statements).

Income Taxes

Income tax expense increased in 2013 over 2012 and in 2012 over 2011 primarily due to increases in income before taxes. The increase in the effective tax rate in 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of the amortization of certain such credits in 2012.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its contractual cash obligations will be met through internally generated funds, the incurrence of additional short- and long-term indebtedness and sales of equity securities. The Company expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. The Company’s ratio of earnings to fixed charges for the year ended December 31, 2013 was 3.22.

Cash requirements for SCANA's regulated subsidiaries arise primarily from their operational needs, funding their construction programs and payment of dividends to SCANA. The ability of the regulated subsidiaries to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental regulations, will depend on their ability to attract the necessary financial capital on reasonable terms. Regulated subsidiaries recover the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and these subsidiaries continue their ongoing construction programs, rate increases will be sought. The future financial position and results of operations of the regulated subsidiaries will be affected by their ability to obtain adequate and timely rate and other regulatory relief.

The Company obtains equity from SCANA’s stock plans. Shares of SCANA common stock are acquired on behalf of participants in SCANA’s Investor Plus Plan and Stock Purchase-Savings Plan through the original issuance of shares, rather than being purchased on the open market. This provided approximately $99 million of additional equity during 2013. Due primarily to new nuclear construction plans, the Company anticipates keeping this strategy in place for the foreseeable future.
In addition, on March 5, 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196 million.

SCANA’s leverage ratio of long- and short-term debt to capital was approximately 56% at December 31, 2013. SCANA has publicly announced its desire to maintain its leverage ratio between 54% and 57%, but SCANA’s ability to do so depends on a number of factors. In the future, if SCANA is not able to maintain its leverage ratio within the desired range, the Company’s debt ratings may be affected, it may be required to pay higher interest rates on its long- and short-term indebtedness, and its access to the capital markets may be limited.

Capital Expenditures

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC, were $1.1 billion in 2013 and are estimated to be $1.7 billion in 2014.

The Company’s current estimates of its capital expenditures for construction and nuclear fuel for 2014-2016, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures			
Millions of dollars	2014	2015	2016
SCE&G - Normal			
Generation	$136	$145	$112
Transmission & Distribution	230	280	258
Other	14	25	19
Gas	50	51	73
Common	9	7	10
Total SCE&G - Normal	439	508	472
PSNC Energy	128	111	87
Other	79	58	42
Total Normal	646	677	601
New Nuclear (including transmission)	950	905	667
Cash Requirements for Construction	1,596	1,582	1,268
Nuclear Fuel	67	30	147
Total Estimated Capital Expenditures	$1,663	$1,612	$1,415

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding liability has been recorded in long-term debt on the consolidated balance sheet.

The Company's contractual cash obligations as of December 31, 2013 are summarized as follows:

Contractual Cash Obligations

	Payments due by periods				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long- and short-term debt, including interest	$10,954	$713	$885	$1,243	$8,113
Capital leases	17	3	10	2	2
Operating leases	41	7	12	3	19
Purchase obligations	3,938	2,067	1,648	221	2
Other commercial commitments	4,397	886	1,700	998	813
Total	$19,347	$3,676	$4,255	$2,467	$8,949

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at the Summer Station site. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output, and the other joint owner (or owners) the remaining 45 percent. Also included in the table above is the estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units as further described in New Nuclear Construction Matters.

Also included in purchase obligations are customary purchase orders under which the Company has the option to utilize certain vendors without the obligation to do so. The Company may terminate such arrangements without penalty.

Other commercial commitments includes estimated obligations under forward contracts for natural gas purchases. Forward contracts for natural gas purchases include customary "make-whole" or default provisions, but are not considered to be "take-or-pay" contracts. Certain of these contracts relate to regulated businesses; therefore, the effects of such contracts on fuel costs are reflected in electric or gas rates. Other commercial commitments also includes a "take-and-pay" contract for natural gas which expires in 2019 and estimated obligations for coal and nuclear fuel purchases.

In addition to the contractual cash obligations above, the Company sponsors a noncontributory defined benefit pension plan and an unfunded health care and life insurance benefit plan for retirees. The pension plan is adequately funded under current regulations, and no significant contributions are anticipated for the foreseeable future. Cash payments under the postretirement health care and life insurance benefit plan were $9.2 million in 2013, and such annual payments are expected to be the same or increase up to $14.7 million in the future.

In addition, the Company is party to certain NYMEX natural gas futures contracts for which any unfavorable market movements are funded in cash. These derivatives are accounted for as cash flow hedges and their effects are reflected within other comprehensive income until the anticipated sales transactions occur. See further discussion at Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. At December 31, 2013, the Company had posted $6.4 million in cash collateral for such contracts. In addition, the Company had posted $20.3 million in cash collateral related to interest rate derivative contracts.

The Company also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations table. See Notes 1 and 10 to the consolidated financial statements.

Financing Limits and Related Matters

The Company's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including state public service commissions and FERC. Financing programs currently utilized by the Company follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million.

GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

In October 2013, the Company's existing committed LOCs were extended by one year. As a result, at December 31, 2013 SCANA, SCE&G (including Fuel Company) and PSNC Energy were parties to five-year credit agreements in the amounts of $300 million, $1.2 billion, of which $500 million relates to Fuel Company, and $100 million, respectively, which expire in October 2018. In addition, at December 31, 2013 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.

As of December 31, 2013, the Company had no outstanding borrowings under its $1.8 billion credit facilities, had approximately $376 million in commercial paper borrowings outstanding, was obligated under $3.3 million in LOC supported letters of credit, and held approximately $136 million in cash and temporary investments. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2013 were approximately $463 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2013, the Company’s long-term debt portfolio has a weighted average maturity of approximately 18 years and bears an average cost of 5.74%. Substantially all of the Company's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, the Company rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

The Company’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCANA’s junior subordinated indenture (relating to the hereinafter defined Hybrids), SCE&G’s bond indenture (relating to the hereinafter defined Bonds) and PSNC Energy’s note purchase and debenture purchase agreements each contain provisions that, under certain circumstances which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013, approximately $63.1 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G’s common stock.

SCANA Corporation

SCANA has an indenture which permits the issuance of unsecured debt securities from time to time including its medium-term notes. This indenture contains no specific limit on the amount of unsecured debt securities which may be issued.

SCANA has outstanding $150 million of enhanced junior subordinated notes (Hybrids) which bear interest at 7.70% and mature on January 30, 2065, subject to extension to January 30, 2080. Because their structure and terms are characteristic of both debt instruments and equity securities, credit rating agencies consider securities like the Hybrids to be hybrid debt instruments and give some equity credit to the issuers of such securities for purposes of computing leverage ratios of debt to capital. The Hybrids are only subject to redemption at SCANA’s option and may be redeemed at any time, although the redemption prices payable by SCANA differ depending on the timing of the redemption and the circumstances (if any) giving rise thereto. SCANA may redeem the Hybrids on or after January 30, 2015, without payment of a make-whole amount.

In connection with the Hybrids, SCANA executed an RCC in favor of the holders of certain designated debt (referred to as “covered debt”). Under the terms of the RCC, SCANA agreed not to redeem or repurchase all or part of the Hybrids prior to the termination date of the RCC, unless it uses the proceeds of certain qualifying securities sold to non-affiliates within 180 days prior to the redemption or repurchase date. The proceeds SCANA receives from such qualifying securities, adjusted by a predetermined factor, must exceed the redemption or repurchase price of the Hybrids. Qualifying securities include common stock, and other securities that generally rank equal to or junior to the Hybrids and include distribution, deferral and long-dated maturity features similar to the Hybrids. For purposes of the RCC, non-affiliates include (but are not limited to) individuals enrolled in SCANA’s dividend reinvestment plan, direct stock purchase plan and employee benefit plans.

The RCC is scheduled to terminate on the earliest to occur of the following: (a) January 30, 2035 (or later, if the maturity date of the Hybrids is extended), (b) the date on which SCANA no longer has any eligible debt which ranks senior in right of payment to the Hybrids, (c) the date on which the holders of at least a majority in principal amount of “covered debt” agree to the termination thereof or (d) the date on which the Hybrids are accelerated following an event of default with respect thereto. SCANA’s $250 million in Medium Term Notes due April 1, 2020 are designated as “covered debt” under the RCC.

South Carolina Electric & Gas Company

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Financing Activities

During 2013 there were net cash outflows related to financing activities of approximately $40 million primarily due to repayment of short- and long-term debt and payment of dividends, partially offset by the issuance of common stock and long-term debt.

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

On March 5, 2013, SCANA settled all forward sales contracts related to 6.6 million shares of its common stock, resulting in net proceeds of approximately $196 million.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.625% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

In November 2012, SCE&G repaid at maturity $4.4 million of 4.2% tax-exempt industrial revenue bonds, and repaid prior to maturity $29.2 million of 5.45% tax-exempt industrial revenue bonds due November 1, 2032.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042 (issued at a premium with a yield of 3.86%), which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds which were issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

In January 2012, SCANA issued $250 million of 4.125% medium term notes due February 1, 2022. Proceeds from the sale were used by SCANA to retire $250 million of its 6.25% medium term notes due February 1, 2012.

Investing Activities

The Company paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt for contracts that had been designated as hedges.

In addition, during the fourth quarter of 2013, the Company received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt. Pursuant to SCPSC accounting orders, $50.1 million of such gains were recognized within other income, with such gain recognition being fully offset by downward adjustments to revenues reflected within electric margin.
For additional information, see Note 4 to the consolidated financial statements.

In February 2014, SCANA increased the quarterly cash dividend rate on SCANA common stock to $.525 per share, an increase of approximately 3.5% from the prior declared dividend. The next quarterly dividend is payable April 1, 2014 to shareholders of record on March 10, 2014.

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act included 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 and 50% bonus depreciation for property placed in service for 2012. The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation for property placed in service in 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of the Company.

ENVIRONMENTAL MATTERS

The Company's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. Compliance with these environmental requirements involves significant capital and operating costs, which the Company expects to recover through existing ratemaking provisions.

For the three years ended December 31, 2013, the Company's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled $46.1 million. In addition, the Company made expenditures to operate and maintain environmental control equipment at its fossil plants of $9.2 million in 2013, $10.2 million in 2012 and $7.9 million during 2011, which are included in “Other operation and maintenance” expense, and made expenditures to handle waste ash of $3.2 million in 2013, $7.9 million in 2012 and $8.7 million in 2011, which are included in “Fuel used in electric generation.” In addition, included within “Other operation and maintenance” expense is an annual amortization of $1.4 million in each of 2013, 2012 and 2011 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for the Company are $9.5 million for 2014 and $82.5 million for the four-year period 2015-2018. These expenditures are included in the Company's Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

At the state level, no significant environmental legislation that would affect the Company's operations advanced during 2013. The Company cannot predict whether such legislation will be introduced or enacted in 2014, or if new regulations or changes to existing regulations at the state level will be implemented in the coming year. Several regulatory initiatives at the federal level did advance in 2013 and more are expected to advance in 2014 as described below.

Air Quality

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, SCANA, SCE&G and GENCO are subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. The Company cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact the Company, and the following discussion should not be considered all-inclusive.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. The Company will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though the Company cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to the Company's electric system, as well as impacts on employees and customers and on the Company's supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. In addition, SCE&G has collected funds from customers for its storm damage reserve (see Note 2 to the consolidated financial statements). As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow the Company to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Water Quality

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility's NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, The Company is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of the Company. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

Hazardous and Solid Wastes

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While the Company cannot predict how extensive the regulations will be, the Company believes that any additional costs imposed by such regulations would be recoverable through rates.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates. The Company has assessed the following matters:

Electric Operations

SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. At December 31, 2013, such regulatory assets totaled approximately $1.2 million. Other environmental costs are recorded to expense as incurred.

Gas Distribution

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC. SCE&G anticipates that major remediation activities at these sites will continue until 2017 and will cost an additional $20.2 million. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. PSNC Energy's actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $2.8 million, the estimated remaining liability at December 31, 2013. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

REGULATORY MATTERS

SCANA and its subsidiaries are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCANA	The SEC as to the issuance of certain securities and other matters and the FERC as to certain acquisitions and other matters.
SCANA and all subsidiaries	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.
PSNC Energy	The NCUC as to gas rates, service, issuance of securities (other than notes with a maturity of two years or less or renewals of notes with a maturity of six years or less), accounting and other matters, and the SEC as to the issuance of certain securities.
SCE&G, PSNC Energy and CGT	The PHMSA and the DOT as to integrity management requirements for gas distribution pipeline systems and natural gas transmission systems, respectively.
CGT	The FERC as to transportation rates, service, accounting and other matters.
SCANA Energy	The GPSC through its certification as a natural gas marketer in Georgia and specifically as to retail prices for customers served under its regulated provider contract.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of the Company’s accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

SCANA’s regulated utilities record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, the Company may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of the Company’s Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of the Company’s regulatory assets and liabilities, including those associated with the Company’s environmental program.

The Company’s generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, the Company could be required to write down its investment in those assets. The Company cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect the Company’s results of operations in the period in which they would be recorded. As of December 31, 2013, the Company’s net investments in fossil/hydro and nuclear generation assets were approximately $2.4 billion and $2.9 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers of the Company’s utilities and retail gas operations are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, the Company records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization or other regulatory provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. Accounts receivable included unbilled revenues of $183.1 million at December 31, 2013 and $189.8 million at December 31, 2012, compared to total revenues of $4.5 billion and $4.2 billion for the years 2013 and 2012, respectively.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G’s accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact the Company’s financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Asset Retirement Obligations

The Company accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The obligations are recognized at present value in the period in which they are incurred, and associated asset retirement costs are capitalized as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to the Company’s regulated utility operations, their recognition has no significant impact on results of operations. As of December 31, 2013, the Company has recorded AROs of $191 million for nuclear plant decommissioning (as discussed above) and AROs of $385 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded in accordance with the relevant accounting guidance are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for the utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

The Company recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. The Company’s plan is adequately funded under current regulations. Accounting guidance requires the use of several assumptions, the selection of which has an impact on the resulting pension cost recorded. Among the more sensitive assumptions are those surrounding discount rates and expected returns on assets. Net pension cost of $31.7 million recorded in 2013 reflects the use of a 4.10% discount rate prior to re-measurement on September 1, 2013 and a 5.07% discount rate after re-measurement, derived using a cash flow matching technique, and an assumed 8.0% long-term rate of return on plan assets. The re-measurement occurred in connection with a plan amendment and related curtailment, which is further described below. The Company believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2013 would have increased the Company’s pension cost by $1.2 million. Further, had the assumed long-term rate of return on assets been 7.75%, the Company’s pension cost for 2013 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

The Company determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, the Company evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2013, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 7.5%, 6.3%, 8.8% and 9.7%, respectively. The 2013 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2014, the plan’s historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. For 2014, the expected rate of return is 8.00%.

As of December 31, 2013, 2012, and 2011, approximately $5.5 million, $14.9 million and $9.0 million, respectively, of pension expense was deferred pursuant to regulatory orders. As part of a December 2012 SCPSC rate order, cumulative previously deferred pension costs related to electric operations of approximately $63 million is being amortized over approximately 30 years, and starting in January 2013 current pension expense for electric operations is being recovered through a pension cost rider. Similarly, in connection with the October 2013 RSA order, previously deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates.

In the third quarter of 2013, the pension plan was amended such that pension benefits will no longer be offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, the Company recorded a curtailment charge due to the accelerated amortization of prior service cost. Approximately $6.5 million of the curtailment charge was applicable to regulated operations and was deferred within regulatory assets. The Company is recovering such deferred amounts through existing regulatory orders.

The closure of the plan to entrants after December 31, 2013 and the cessation of benefit accruals in 2023 are expected to further lessen the significance of pension costs and the criticality of the related estimates to the Company's financial statements. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

The Company accounts for the cost of its postretirement medical and life insurance benefit plans in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. The Company used a discount rate of 4.19%, derived using a cash flow matching technique, and recorded a net cost of $21.3 million for 2013. Had the selected discount rate been 3.94% (25 basis points lower than the discount rate referenced above), the expense for 2013 would have been $0.6 million higher. Because the plan provisions include “caps” on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

It is expected that Unit 2 will be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in revised rates filings under the BLRA.

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first

New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2 to the consolidated financial statements. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide for detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification. Under current provisions of the Internal Revenue Code and based on SCE&G's current 55% ownership and other assumptions regarding volumes of electricity to be generated by the New Units, the aggregate production tax credits for which SCE&G qualifies could exceed $1.3 billion over the eight year period following each of the New

Units' in-service dates. In January 2014, SCE&G amended its application to include the additional 5% interest in the New Units that it expects to acquire. Additional production tax credits related to the 5% interest could total as much as $125 million.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. The Company has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. The Company is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Transactions

Although SCANA invests in securities and business ventures, it does not hold significant investments in unconsolidated special purpose entities. SCANA does not engage in off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by the Company described below are held for purposes other than trading.

Interest Rate Risk

The tables below provides information about long-term debt issued by the Company and other financial instruments that are sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average interest rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

December 31, 2013	Expected Maturity Date							
Millions of dollars	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	46.7	10.8	109.6	8.7	717.9	4,386.5	5,280.2	5,753.3
Average Fixed Interest Rate (%)	4.83	4.72	1.14	4.84	5.95	5.43	5.40	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	138.2	160.2	154.4
Average Variable Interest Rate (%)	0.94	0.94	0.94	0.94	0.94	0.53	0.59	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	604.4	654.4	4.4	4.4	4.4	141.8	1,413.8	13.0
Average Pay Interest Rate (%)	3.97	4.17	6.17	6.17	6.17	4.72	4.16	—
Average Receive Interest Rate (%)	0.25	0.25	0.94	0.94	0.94	0.49	0.28	—

December 31, 2012	Expected Maturity Date							
Millions of dollars	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	162.0	46.1	9.8	8.6	7.7	4,706.0	4,940.2	5,941.4
Average Fixed Interest Rate (%)	6.96	4.86	4.92	5.03	5.12	5.59	5.63	—
Variable Rate ($)	4.4	4.4	4.4	4.4	4.4	142.6	164.6	157.5
Average Variable Interest Rate (%)	1.01	1.01	1.01	1.01	1.01	0.61	0.66	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	604.4	304.4	4.4	4.4	4.4	146.2	1,068.2	(33.6)
Average Pay Interest Rate (%)	3.04	2.53	6.17	6.17	6.17	4.76	3.17	—
	0.31	0.32	1.01	1.01	1.01	0.58	0.36	—

Average Receive Interest Rate
(%)

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013 and $9 million at December 31, 2012, which amounts do not have a stated interest rate associated with them.

For further discussion of the Company’s long-term debt and interest rate derivatives, see Item 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

Commodity Price Risk

The following tables provide information about the Company’s financial instruments that are sensitive to changes in natural gas prices. Weighted average settlement prices are per 10,000 MMBTU. Fair value represents quoted market prices.

Expected Maturity:

Futures Contracts			Options		
				Purchased Call	Purchased Put
2014	Long	Short	2014	(Long)	(Short)
Settlement Price (a)	4.18	4.17	Strike Price (a)	4.01	4.10
Contract Amount (b)	13.0	0.7	Contract Amount (b)	26.6	0.2
Fair Value (b)	14.0	0.7	Fair Value (b)	2.2	—
2015			2015		
Settlement Price (a)	4.27	4.1	Strike Price (a)	4.30	—
Contract Amount (b)	1.1	0.2	Contract Amount (b)	0.1	—
Fair Value (b)	1.2	0.2	Fair Value (b)	—	—

(a) Weighted average, in dollars
(b) Millions of dollars

Swaps	2014	2015	2016	2017
Commodity Swaps:				
Pay fixed/receive variable (b)	51.9	17.1	10.0	1.0
Average pay rate (a)	4.2063	4.9039	4.7098	4.1275
Average received rate (a)	4.1774	4.1634	4.1284	4.1530
Fair Value (b)	51.6	14.5	8.8	1.1
Pay variable/receive fixed (b)	32.4	14.0	8.7	1.1
Average pay rate (a)	4.1720	4.1621	4.1296	4.1530
Average received rate (a)	4.2845	4.9363	4.7143	4.1325
Fair Value (b)	33.3	16.6	9.9	1.1
Basis Swaps:				
Pay variable/receive variable (b)	1.0	0.5	—	—
Average pay rate (a)	4.2256	4.3982	—	—
Average received rate (a)	4.1700	4.3767	—	—
Fair Value (b)	1.0	0.5	—	—

(a) Weighted average, in dollars
(b) Millions of dollars

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 to the consolidated financial statements. The information above includes those financial positions of Energy Marketing and PSNC Energy.

PSNC Energy utilizes futures, options and swaps to hedge gas purchasing activities. PSNC Energy’s tariffs include a provision for the recovery of actual gas costs incurred. PSNC Energy defers premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program for subsequent recovery from customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and changes in common equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control-Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Assets		
Utility Plant In Service	$12,213	$11,865
Accumulated Depreciation and Amortization	(4,011)	(3,811)
Construction Work in Progress	2,724	2,084
Plant to be Retired, Net	177	362
Nuclear Fuel, Net of Accumulated Amortization	310	166
Goodwill	230	230
Utility Plant, Net	11,643	10,896
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $150 and $139	317	306
Assets held in trust, net-nuclear decommissioning	101	94
Other investments	86	87
Nonutility Property and Investments, Net	504	487
Current Assets:		
Cash and cash equivalents	136	72
Receivables, net of allowance for uncollectible accounts of $6 and $7	802	780
Inventories:		
Fuel	231	304
Materials and supplies	131	136
Emission allowances	1	1
Prepayments and other	120	223
Deferred income taxes	—	11
Total Current Assets	1,421	1,527
Deferred Debits and Other Assets:		
Regulatory assets	1,360	1,464
Pension asset	47	—
Other	189	242
Total Deferred Debits and Other Assets	1,596	1,706
Total	$15,164	$14,616

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Capitalization and Liabilities		
Common equity	$4,664	$4,154
Long-Term Debt, Net	5,395	4,949
Total Capitalization	10,059	9,103
Current Liabilities:		
Short-term borrowings	376	623
Current portion of long-term debt	54	172
Accounts payable	425	428
Customer deposits and customer prepayments	88	86
Taxes accrued	206	164
Interest accrued	82	82
Dividends declared	69	66
Derivative financial instruments	8	80
Other	134	110
Total Current Liabilities	1,442	1,811
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,703	1,653
Deferred investment tax credits	32	36
Asset retirement obligations	576	561
Postretirement benefits	227	387
Regulatory liabilities	966	882
Other	159	183
Total Deferred Credits and Other Liabilities	3,663	3,702
Commitments and Contingencies (Note 10)	—	—
Total	$15,164	$14,616

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31, (Millions of dollars, except per share amounts)	2013	2012	2011
Operating Revenues:			
Electric	$2,423	$2,446	$2,424
Gas-regulated	955	774	849
Gas-nonregulated	1,117	956	1,136
Total Operating Revenues	4,495	4,176	4,409
Operating Expenses:			
Fuel used in electric generation	745	838	917
Purchased power	43	28	19
Gas purchased for resale	1,491	1,198	1,455
Other operation and maintenance	708	690	658
Depreciation and amortization	378	356	346
Other taxes	220	207	201
Total Operating Expenses	3,585	3,317	3,596
Operating Income	910	859	813
Other Income (Expense):			
Other income	100	59	52
Other expenses	(46)	(42)	(40)
Interest charges, net of allowance for borrowed funds used during construction of $14, $11 and $7	(297)	(295)	(284)
Allowance for equity funds used during construction	27	21	14
Total Other Expense	(216)	(257)	(258)
Income Before Income Tax Expense	694	602	555
Income Tax Expense	223	182	168
Net Income	$471	$420	$387
Per Common Share Data			
Basic Earnings Per Share of Common Stock	$3.40	$3.20	$3.01
Diluted Earnings Per Share of Common Stock	3.39	3.15	2.97
Weighted Average Common Shares Outstanding (millions)			
Basic	138.7	131.1	128.8
Diluted	139.1	133.3	130.2

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2013	2012	2011
Net Income	$471	$420	$387
Other Comprehensive Income (Loss), net of tax:			
Unrealized Losses on Cash Flow Hedging Activities:			
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $4, $(5) and $(36)	7	(8)	(58)
Losses on cash flow hedging activities reclassified to net income, net of tax of $7, $12 and $8	11	19	13
Net unrealized gains (losses) on cash flow hedging activities	18	11	(45)
Deferred Costs of Employee Benefit Plans:			
Deferred costs of employee benefit plans, net of tax of $4, $(2) and $(2)	7	(4)	(3)
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax of $-, $- and $-	1	1	1
Net deferred costs of employee benefit plans	8	(3)	(2)
Other Comprehensive Income (Loss)	26	8	(47)
Total Comprehensive Income	$497	$428	$340

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Cash Flows From Operating Activities:			
Net Income	$471	$420	$387
Adjustments to reconcile net income to net cash provided from operating activities:			
Earnings from equity method investments, net of distributions	7	—	2
Deferred income taxes, net	49	130	164
Depreciation and amortization	393	368	354
Amortization of nuclear fuel	57	44	40
Allowance for equity funds used during construction	(27)	(21)	(14)
Carrying cost recovery	(3)	—	—
Changes in certain assets and liabilities:			
Receivables	(38)	5	34
Inventories	21	(53)	(44)
Prepayments and other	(12)	3	58
Regulatory assets	113	(172)	(173)
Regulatory liabilities	56	62	(17)
Accounts payable	24	34	(99)
Taxes accrued	42	10	8
Interest accrued	—	8	2
Pension and other postretirement benefits	(217)	89	90
Other assets	78	(120)	34
Other liabilities	36	32	(15)
Net Cash Provided From Operating Activities	1,050	839	811
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,106)	(1,077)	(884)
Proceeds from investments (including derivative collateral posted)	222	472	36
Purchase of investments (including derivative collateral posted)	(176)	(414)	(168)
Payments upon interest rate derivative contract settlement	(49)	(51)	(61)
Proceeds from interest rate derivative contract settlement	163	14	—
Net Cash Used For Investing Activities	(946)	(1,056)	(1,077)
Cash Flows From Financing Activities:			
Proceeds from issuance of common stock	295	97	97
Proceeds from issuance of long-term debt	451	759	826
Repayments of long-term debt	(258)	(309)	(668)
Dividends	(281)	(257)	(248)
Short-term borrowings, net	(247)	(30)	233
Net Cash Provided From (Used For) Financing Activities	(40)	260	240
Net Increase (Decrease) in Cash and Cash Equivalents	64	43	(26)
Cash and Cash Equivalents, January 1	72	29	55
Cash and Cash Equivalents, December 31	$136	$72	$29
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $14, $11 and $7)	$288	$281	$276
—Income taxes	104	107	6
Noncash Investing and Financing Activities:			
Accrued construction expenditures	111	124	85

Capital leases	6	8	6
Nuclear fuel purchase	98	—	—

See Notes to Consolidated Financial Statements.

SCANA Corporation
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON EQUITY

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Loss	Total
Balance as of January 1, 2011	127	$1,789	$1,960	$(47)	$3,702
Net Income			387		387
Other Comprehensive Loss, net of taxes of $(29)				(47)	(47)
Total Comprehensive Income (Loss)			387	(47)	340
Issuance of Common Stock	3	97			97
Dividends Declared			(250)		(250)
Balance as of December 31, 2011	130	1,886	2,097	(94)	3,889
Net Income			420		420
Other Comprehensive Income, net of taxes of $5				8	8
Total Comprehensive Income			420	8	428
Issuance of Common Stock	2	97			97
Dividends Declared			(260)		(260)
Balance as of December 31, 2012	132	1,983	2,257	(86)	4,154
Net Income			471		471
Other Comprehensive Income, net of taxes of $16				26	26
Total Comprehensive Income			471	26	497
Issuance of Common Stock	9	297			297
Dividends Declared			(284)		(284)
Balance as of December 31, 2013	141	$2,280	$2,444	$(60)	$4,664

Dividends declared per share of common stock were $2.03, $1.98 and $1.94 for 2013, 2012 and 2011, respectively.

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCANA, a South Carolina corporation, is a holding company. The Company engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to wholesale and retail customers in South Carolina, North Carolina and Georgia. The Company also conducts other energy-related business and provides fiber optic communications in South Carolina.

The accompanying consolidated financial statements reflect the accounts of SCANA and the following wholly-owned subsidiaries.

Regulated businesses	Nonregulated businesses
South Carolina Electric & Gas Company	SCANA Energy Marketing, Inc.
South Carolina Fuel Company, Inc.	SCANA Communications, Inc.
South Carolina Generating Company, Inc.	ServiceCare, Inc.
Public Service Company of North Carolina, Incorporated	SCANA Services, Inc.
Carolina Gas Transmission Corporation	SCANA Corporate Security Services, Inc.

The Company reports certain investments using the cost or equity method of accounting, as appropriate. Intercompany balances and transactions have been eliminated in consolidation, with the exception of profits on intercompany sales to regulated affiliates if the sales price is reasonable and the future recovery of the sales price through the rate-making process is probable, as permitted by accounting guidance.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset’s life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. The Company’s regulated subsidiaries calculated AFC using average composite rates of 6.9% for 2013, 6.3% for 2012 and 4.7% for 2011. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

The Company records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were as follows:

	2013	2012	2011
SCE&G	2.96 %	2.93 %	2.92 %
GENCO	2.66 %	2.66 %	2.69 %
CGT	2.19 %	2.09 %	2.00 %
PSNC Energy	3.01 %	3.01 %	3.05 %
Aggregate of Above	2.93 %	2.90 %	2.90 %

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2013		2012	
	Unit 1	New Units	Unit 1	New Units
Percent owned	66.7%	55.0%	66.7%	55.0%
Plant in service	$1.1 billion	—	$1.1 billion	—
Accumulated depreciation	$566.9 million	—	$557.0 million	—
Construction work in progress	$127.1 million	$2.3 billion	$113.6 million	$1.8 billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC. For a discussion of when the New Units are expected to be placed in service, and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $75.6 million at December 31, 2013 and $92.9 million at December 31, 2012.

Plant to be Retired

As previously disclosed, in 2012 SCE&G identified a total of six coal-fired units that it intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. As of December 31, 2013, three of these units had been retired and their net carrying value is recorded in regulatory assets (see Note 2). The net carrying value of the remaining units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these remaining units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the consolidated balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2013 and 2012, SCE&G incurred $18.1 million and $11.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from January 2010 through December 2012 for its portion of the outages in the spring of 2011 and the fall of 2012. Total costs for the 2011 outage were $34.1 million, of which SCE&G was responsible for $22.7 million. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur through the spring of 2020.

Goodwill

The Company considers amounts categorized by FERC as “acquisition adjustments” with carrying values of $210 million (net of writedown of $230 million) for PSNC Energy (Gas Distribution segment) and $20 million for CGT (All Other segment) to be goodwill. The Company tests these goodwill amounts for impairment annually as of January 1, unless indicators, events or circumstances require interim testing to be performed. The goodwill impairment testing is generally a two-step quantitative process which in step one requires estimation of the fair value of the respective reporting unit and the comparison of that amount to its carrying value. If this step indicates an impairment (a carrying value in excess of fair value), then step two, measurement of the amount of the goodwill impairment (if any), is required. In the first quarter of 2012, the Company adopted guidance under which it has the option to first perform a qualitative assessment of impairment. Based on this qualitative ("step zero") assessment, if the Company determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company is not required to proceed with the two-step quantitative assessment.

In evaluations of PSNC Energy, fair value was estimated using the assistance of an independent appraisal. In evaluations of CGT, prior to the adoption of the new guidance, estimated fair value was obtained from discounted cash flow and other analysis. Step zero was utilized for CGT’s evaluation as of January 1, 2013, and step one (via discounted cash flow and other analysis) was again utilized for the evaluation as of January 1, 2014. In all evaluations for the periods presented, step one or step zero, as applicable, has indicated no impairment. The estimated fair values of the reporting units are substantially in excess of their carrying values, and no impairment charges have been recorded; however, should a write-down be required in the future, such a charge would be treated as an operating expense.

Nuclear Decommissioning

SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars, pursuant to an updated decommissioning cost study performed in 2012. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2013, 2012 and 2011) are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

The Company considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

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 used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC or NCUC, as applicable. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Asset Management and Supply Service Agreements

PSNC Energy utilizes asset management and supply service agreements with counterparties for certain natural gas storage facilities. Such counterparties held 48% and 44% of PSNC Energy's natural gas inventory at December 31, 2013 and December 31, 2012, respectively, with a carrying value of $22.8 million and $19.6 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees. No fees are received under supply service agreements. The agreements expire March 31, 2015.

Income Taxes

The Company files a consolidated federal income tax return. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers of the Company's regulated subsidiaries; otherwise, they are charged or credited to income tax expense.

Regulatory Assets and Regulatory Liabilities

The Company's rate-regulated utilities record costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

The Company records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. For regulated subsidiaries, other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense as incurred.

Income Statement Presentation

In its consolidated statements of income, the Company presents the revenues and expenses of its regulated businesses and its retail natural gas marketing businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

The Company records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $183.1 million at December 31, 2013 and $189.8 million at December 31, 2012.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

SCE&G customers subject to a PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor. PSNC Energy’s PGA mechanism authorized by the NCUC allows the recovery of all prudently incurred gas costs, including the results of its hedging program, from customers. Any difference between actual gas costs and amounts contained in rates is deferred and included when establishing gas costs during subsequent PGA filings or in annual prudence reviews.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

PSNC Energy is authorized by the NCUC to utilize a CUT which allows it to adjust base rates semi-annually for residential and commercial customers based on average per customer consumption, whether impacted by weather or other factors.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

Earnings Per Share

The Company computes basic earnings per share by dividing net income by the weighted average number of common shares outstanding for the period. The Company computes diluted earnings per share using this same formula, after giving effect to securities considered to be dilutive potential common stock utilizing the treasury stock method. The

Company has issued no securities that would have an antidilutive effect on earnings per share.

A reconciliation of the weighted average number of common shares for each of the three years ended December 31, for basic and diluted purposes is as follows:

In Millions	2013	2012	2011
Weighted Average Shares Outstanding—Basic	138.7	131.1	128.8
Net effect of equity forward contracts	0.4	2.2	1.4
Weighted Average Shares Outstanding—Diluted	139.1	133.3	130.2

2. RATE AND OTHER REGULATORY MATTERS

Rate Matters

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a twelve month period beginning with the first billing cycle of May 2012.

This April 2012 order was superseded, in part, by a December 2012 rate order in which the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014 except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, SCE&G did not request any adjustment to its base fuel cost component. In March 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the under-collected balance of fuel costs. The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component. A public hearing for the annual review of base rates for fuel costs has been scheduled for April 3, 2014.

Pursuant to a November 2013 SCPSC accounting order, the Company's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and during 2013, $2.9 million of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills and had been in use since August 2010. In connection with the December 2012 order, SCE&G agreed to perform a study of alternative structures for eWNA. On November 1, 2013, the ORS filed a report with the SCPSC recommending that the eWNA be terminated with the last billing cycle for December 2013. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition.

In connection with the above termination of the eWNA program effective December 31, 2013, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. Pursuant to the SCPSC accounting order granting the above relief and terminating the eWNA, such revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and two others were retired in the fourth quarter of 2013. The net carrying value of these retired units is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

In a July 2010 order, the SCPSC provided for a $48.7 million credit to SCE&G's customers over two years to be offset by accelerated recognition of previously deferred state income tax credits. These tax credits were fully amortized in 2012.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and lost net margin revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

Other activity related to SCE&G’s DSM Programs is as follows:

- In May 2013 the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.

- In November 2013 the SCPSC approved SCE&G’s continued use of DSM programs for another six years, including approval of the rate rider mechanism and a revised portfolio of DSM programs.

- In January 2014 SCE&G submitted its annual DSM Programs filing to the SCPSC, which included, among other things, a request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of the gains from the recent settlement of certain interest rate derivative instruments to offset a portion of the net lost revenues component of SCE&G’s DSM Programs rider, and (3) apply $5 million of its storm damage reserve and a portion of the gains from the recent settlement of certain interest rate derivative instruments, currently estimated to be $5.5 million, to the remaining balance of deferred net lost revenue as of April 30, 2014, deferred within regulatory assets resulting from the May 2013 order previously described.

Electric - BLRA

In May 2011, the SCPSC approved an updated capital cost schedule sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs of $173.9 million (SCE&G's portion in 2007 dollars).

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount	
2013	2.90%	$67.2	million
2012	2.30%	$52.1	million
2011	2.40%	$52.8	million

Gas

SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action		Amount	
2013	No change			
2012	2.10	% Increase	$7.5	million
2011	2.10	% Increase	$8.6	million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2013 and 2012 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

PSNC Energy

PSNC Energy is subject to a Rider D rate mechanism which allows it to recover from customers all prudently incurred gas costs and certain uncollectible expenses related to gas cost. The Rider D rate mechanism also allows PSNC Energy to recover, in any manner authorized by the NCUC, losses on negotiated gas and transportation sales.

PSNC Energy's rates are established using a benchmark cost of gas approved by the NCUC, which may be periodically adjusted to reflect changes in the market price of natural gas. PSNC Energy revises its tariffs with the NCUC as necessary to track these changes and accounts for any over- or under-collection of the delivered cost of gas in its deferred accounts for subsequent rate consideration. The NCUC reviews PSNC Energy's gas purchasing practices annually. In addition, PSNC Energy utilizes a CUT which allows it to adjust its base rates semi-annually for residential and commercial customers based on average per customer consumption.

In October 2013, in connection with PSNC Energy's 2013 Annual Prudence Review, the NCUC issued an order finding that PSNC Energy's gas costs, including all hedging transactions, were reasonable and prudently incurred during the 12 months ended March 31, 2013.

During the third quarter of 2013, the State of North Carolina passed legislation that makes changes to statutes covering gross receipts, sales and use, excise, franchise and income taxes. In the fourth quarter, in response to this legislation, the

NCUC initiated a proceeding to investigate how it should proceed in response to the enactment of such legislation. Because the investigation was not completed before January 1, 2014, the NCUC issued an order notifying utilities that the incremental revenue requirement impact associated with the change in the level of state income tax expense included in each utility's cost of service would be deemed to be collected on a provisional basis (subject to refund) beginning January 1, 2014.

Regulatory Assets and Regulatory Liabilities

The Company's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, the Company has recorded regulatory assets and regulatory liabilities which are summarized in the following tables. Other than unrecovered plant, substantially all of our regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	2013	2012
Regulatory Assets:		
Accumulated deferred income taxes	$259	$254
Under-collections—electric fuel adjustment clause	18	66
Environmental remediation costs	41	44
AROs and related funding	368	319
Franchise agreements	31	36
Deferred employee benefit plan costs	238	460
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	124	151
Deferred pollution control costs	37	38
Unrecovered plant	145	20
DSM Programs	51	27
Other	48	43
Total Regulatory Assets	$1,360	$1,464
Regulatory Liabilities:		
Accumulated deferred income taxes	$24	$21
Asset removal costs	695	692
Storm damage reserve	27	27
Monetization of bankruptcy claim	29	32
Deferred gains on interest rate derivatives	181	110
Planned major maintenance	10	—
Total Regulatory Liabilities	$966	$882

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by the Company, and are expected to be recovered over periods of up to approximately 26 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on a SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are being recovered through utility rates over approximately 30 years. In connection with the October 2013 RSA order, approximately $14 million of deferred pension costs for gas operations are being recovered through utility rates over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for such equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G collects and accrues $16.8 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the installation of scrubbers at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives, or up to approximately 14 years. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represents deferred costs and certain unrecovered lost revenue associated with SCE&G’s Demand Side Management programs. Deferred costs are currently being recovered over 5 years through a SCPSC approved rider. Unrecovered lost revenue is to be recovered over periods not to exceed 24 months from date of deferral. See Rate Matters - Electric Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs and unrecovered lost revenue.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The monetization of bankruptcy claim represents proceeds from the sale of a bankruptcy claim which are expected to be amortized into operating revenue through February 2024.

The SCPSC, the NCUC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC, the NCUC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by the Company. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, the Company could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the Company's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. COMMON EQUITY

The Company's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCANA's junior subordinated indenture (relating to the Hybrids), SCE&G's bond indenture (relating to the Bonds) and PSNC Energy's note purchase and debenture purchase agreements each contain provisions that, under certain circumstances, which the Company considers to be remote, could limit the payment of cash dividends on their respective common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013 and 2012, approximately $63.1 million and $61.0 million of retained earnings, respectively, were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

Cash dividends on SCANA's common stock were declared during 2013, 2012 and 2011 at an annual rate per share of $2.03, $1.98 and $1.94, respectively.

The accumulated balances related to each component of accumulated other comprehensive income (loss), net of tax, were as follows:

Millions of Dollars	Gains (Losses) on Cash Flow Hedges	Deferred Employee Benefit Plans	Accumulated Other Comprehensive Income (Loss)
Accumulated Other Comprehensive Loss as of January 1, 2012	$(81)	$(13)	$ (94)
Other comprehensive income (loss)	11	(3)	8
Accumulated Other Comprehensive Loss as of December 31, 2012	(70)	(16)	(86)
Other comprehensive income	18	8	26
Accumulated Other Comprehensive Loss as of December 31, 2013	$(52)	$(8)	$ (60)

Authorized shares of common stock were 200 million as of December 31, 2013 and 2012.

SCANA issued common stock valued at $100.9 million, $97.7 million and $97.8 million (when issued) during the years ended December 31, 2013, 2012 and 2011, respectively, which was satisfied using original issue shares, through various compensation and dividend reinvestment plans, including the Stock Purchase Savings Plan.

In March 2013, SCANA settled all forward sales contracts related to its common stock through the issuance of approximately 6.6 million common shares, resulting in net proceeds of approximately $196.2 million.

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4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2013 Balance	Rate		2012 Balance	Rate	
Medium Term Notes (unsecured)	2020 - 2022	$800	5.42	%	$800	5.02	%
Senior Notes (unsecured) (a)	2034	92	0.94	%	96	1.01	%
First Mortgage Bonds (secured)	2018 - 2042	3,540	5.60	%	3,290	5.66	%
Junior Subordinated Notes (unsecured) (b)	2065	150	7.92	%	150	7.70	%
GENCO Notes (secured)	2018 - 2024	233	5.89	%	240	5.87	%
Industrial and Pollution Control Bonds (c)	2014 - 2038	158	3.83	%	161	4.32	%
Senior Debentures	2020- 2026	350	5.93	%	350	5.90	%
Nuclear Fuel Financing	2016	100	0.78	%	—	—	
Other	2014 - 2027	20	2.73	%	27	2.39	%
Total debt		5,443			5,114		
Current maturities of long-term debt		(54	)		(172	)	
Unamortized premium (discount)		6			7		
Total long-term debt, net		$5,395			$4,949		

(a) Variable rate notes hedged by a fixed interest rate swap (fixed rate of 6.47%)
(b) May be extended through 2080
(c) Includes variable rate debt of $67.8 million at December 31, 2013 (rate of 0.11%) and 2012 (rate of 0.17%) which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the years 2014 through 2018 are summarized as follows:

Year	Millions of dollars
2014	$54
2015	15
2016	114
2017	13
2018	722

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027. The borrowings refinanced by these 2013 issuances are classified within Long-term Debt, Net in the consolidated balance sheet.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042, which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

In January 2012, SCANA issued $250 million of 4.125% medium term notes due February 1, 2022. Proceeds from the sale were used to retire SCANA's $250 million 6.25% medium term notes due February 1, 2012.

Substantially all of SCE&G's and GENCO's electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Lines of Credit and Short-Term Borrowings

At December 31, 2013 and 2012, SCANA, SCE&G (including Fuel Company) and PSNC Energy had available the following committed LOC and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

	SCANA		SCE&G		PSNC Energy	
Millions of dollars	2013	2012	2013	2012	2013	2012
Lines of Credit:						
Total committed long-term	$300	$300	$1,400	$1,400	$100	$100
LOC advances	—	—	—	—	—	—
Weighted average interest rate	—	—	—	—	—	—
Outstanding commercial paper (270 or fewer days)	$125	$142	$251	$449	—	$32
Weighted average interest rate	0.39 %	0.58 %	0.27 %	0.42 %	—	0.44 %
Letters of credit supported by LOC	$3	$3	$0.3	$0.3	—	—
Available	$172	$155	$1,149	$951	$100	$68

SCANA, SCE&G (including Fuel Company) and PSNC Energy are parties to five-year credit agreements in the amounts of $300 million, $1.2 billion (of which $500 million relates to Fuel Company) and $100 million, respectively. In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2013, the term of each of these credit agreements was extended by one year, such that the five-year agreements expire in October 2018, and the three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N.A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1.8 billion credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9%, and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. The Company pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented. The Company is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. The letters of credit expire, subject to renewal, in the fourth quarter of 2014.

The Company pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

5. INCOME TAXES

Components of income tax expense for 2013, 2012 and 2011 are as follows:

Millions of dollars	2013	2012	2011
Current taxes:			
Federal	$161	$103	$52
State	17	10	10
Total current taxes	178	113	62
Deferred taxes, net:			
Federal	39	72	122
State	10	14	12
Total deferred taxes	49	86	134
Investment tax credits:			
Amortization of amounts deferred-state	(1)	(14)	(25)
Amortization of amounts deferred-federal	(3)	(3)	(3)
Total investment tax credits	(4)	(17)	(28)
Total income tax expense	$223	$182	$168

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2013	2012	2011
Net income	$471	$420	$387
Income tax expense	223	182	168
Total pre-tax income	$694	$602	$555
Income taxes on above at statutory federal income tax rate	$243	$211	$194
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	22	19	15
State investment tax credits (less federal income tax effect)	(5)	(13)	(16)
Allowance for equity funds used during construction	(9)	(8)	(5)
Deductible dividends—Stock Purchase Savings Plan	(10)	(9)	(9)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 45 tax credits	(5)	(5)	(2)
Domestic production activities deduction	(11)	(9)	(6)
Other differences, net	1	(1)	—
Total income tax expense	$223	$182	$168

The tax effects of significant temporary differences comprising the Company's net deferred tax liability at December 31, 2013 and 2012 are as follows:

Millions of dollars	2013	2012
Deferred tax assets:		
Nondeductible accruals	$84	$143
Asset retirement obligation, including nuclear decommissioning	220	214
Financial instruments	32	43
Unamortized investment tax credits	19	22
Regulatory liability, net gain on interest rate derivative contracts settlement	27	—
Unbilled revenue	—	14
Monetization of bankruptcy claim	11	12
Other	13	15
Total deferred tax assets	406	463
Deferred tax liabilities:		
Property, plant and equipment	$1,765	$1,718
Deferred employee benefit plan costs	63	148
Regulatory asset-asset retirement obligation	121	113
Deferred fuel costs	25	48
Regulatory asset, unrecovered plant	55	7
Other	84	71
Total deferred tax liabilities	2,113	2,105
Net deferred tax liability	$1,707	$1,642

During the third quarter of 2013, the State of North Carolina passed legislation that lowered the state corporate income tax rate from 6.9% to 6.0% in 2014 and 5.0% in 2015. In connection with this change in tax rates, related state deferred tax amounts were remeasured, with the change in their balances being credited to a regulatory liability. The change in income tax rates did not and is not expected to have a material impact on the Company's financial position, results of operations or cash flows. Additionally, during the third quarter of 2013, the IRS issued final regulations regarding the capitalization of certain costs for income tax purposes and re-proposed certain other related regulations (collectively referred to as tangible personal property regulations). Related IRS revenue procedures were then issued on January 24, 2014. These regulations did not and are not expected to, have a material impact on the Company's financial position, results of operations or cash flows.

The Company files a consolidated federal income tax return, and the Company and its subsidiaries file various applicable state and local income tax returns. The IRS has completed examinations of the Company's federal returns through 2004, and the Company's federal returns through 2007 are closed for additional assessment. With few exceptions, the Company is no longer subject to state and local income tax examinations by tax authorities for years before 2009.

Changes to Unrecognized Tax Benefits

Millions of dollars	2013	2012	2011
Unrecognized tax benefits, January 1	—	$38	$36
Gross increases—uncertain tax positions in prior period	—	—	5
Gross decreases—uncertain tax positions in prior period	—	(38)	(8)
Gross increases—current period uncertain tax positions	$3	—	5
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$3	$—	$38

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative

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guidance from the IRS allowed the Company to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Company's effective tax rate.

During 2013, the Company amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, the Company recorded an unrecognized tax benefit of $3 million. If recognized, this tax benefit would affect the Company’s effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $5 million within the next 12 months. No other material changes in the status of the Company’s tax positions have occurred through December 31, 2013.
The Company recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 the Company reversed $2 million of interest expense which had been accrued during 2011. The Company has not recorded interest expense or penalties associated with the 2013 uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. The Company recognizes changes in the fair value of derivative instruments either in earnings, as a component of other comprehensive income (loss) or, for regulated subsidiaries, within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by the Company. SCANA’s Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries. The Risk Management Committee, which is comprised of certain officers, including the Company’s Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. Instruments designated as fair value hedges are used to mitigate exposure to fluctuating market prices created by fixed prices of stored natural gas. The basic types of financial instruments utilized are exchange-traded instruments, such as NYMEX futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy companies and financial institutions. Cash settlements of commodity derivatives are classified as operating activities in the consolidated statement of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and swaps and NYMEX futures and options. PSNC Energy’s tariffs also include a provision for the recovery of actual gas costs incurred, including any costs of hedging. PSNC Energy records premiums, transaction fees, margin requirements and any realized gains or losses from its hedging program in deferred accounts as a regulatory asset or liability for the over- or under-recovery of gas costs. These derivative financial instruments are not designated as hedges for accounting purposes.

Unrealized gains and losses on qualifying cash flow hedges of nonregulated operations are deferred in AOCI. When the hedged transactions affect earnings, previously recorded gains and losses are reclassified from AOCI to cost of gas. The effects of gains or losses resulting from these hedging activities are either offset by the recording of the related hedged transactions or are included in gas sales pricing decisions made by the business unit.

As an accommodation to certain customers, SEMI, as part of its energy management services, offers fixed price supply contracts which are accounted for as derivatives. These sales contracts are offset by the purchase of supply futures and swaps which are also accounted for as derivatives. Neither the sales contracts nor the related supply futures and swaps are designated as hedges for accounting purposes.

Interest Rate Swaps

The Company may use interest rate swaps to manage interest rate risk and exposure to changes in fair value attributable to changes in interest rates on certain debt issuances. In cases in which the Company synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges, periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, the Company may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. Except as described in the following paragraph, the effective portions of changes in fair value and payments made or received upon termination of such agreements for regulated subsidiaries are recorded in regulatory assets or regulatory liabilities. For the holding company or nonregulated subsidiaries, such amounts are recorded in AOCI. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions of fair value changes are recognized in income.

Pursuant to regulatory orders issued in 2013, interest rate derivatives entered into by SCE&G after October 2013 are no longer designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Upon settlement, losses on swaps will be amortized over the lives of related debt issuances, and gains may be applied to under-collected fuel, be amortized to interest expense or applied as otherwise directed by the SCPSC. As discussed in Note 2, in these orders, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

The Company was party to natural gas derivative contracts outstanding in the following quantities:

	Commodity and Other Energy Management Contracts (in MMBTU)			
Hedge designation	Gas Distribution	Retail Gas Marketing	Energy Marketing	Total
As of December 31, 2013				
Commodity	6,070,000	6,726,000	2,560,000	15,356,000
Energy Management (a)	—	—	27,359,958	27,359,958
Total (a)	6,070,000	6,726,000	29,919,958	42,715,958
As of December 31, 2012				
Commodity	5,170,000	6,490,000	4,877,000	16,537,000
Energy Management (b)	—	—	31,763,275	31,763,275
Total (b)	5,170,000	6,490,000	36,640,275	48,300,275

(a) Includes an aggregate 348,453 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 3,500,000 MMBTU related to basis swap contracts in Energy Marketing.

The Company was party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $128.8 million at December 31, 2013, and $1.1 billion at December 31, 2012. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.3 billion and $0.0 million at December 31, 2013 and 2012, respectively.

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The fair value of energy-related derivatives and interest rate derivatives was reflected in the consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Other current liabilities	$5
			Other deferred credits and other liabilities	14
Commodity contracts	Prepayments and other	$2		
Total		$2		$19
Derivatives not designated as hedging instruments				
Interest rate contracts	Prepayments and other	$13	Other current liabilities	$1
	Other deferred debits and other assets	19		
Commodity contracts	Prepayments and other	2		
Energy management contracts	Prepayments and other	4	Other current liabilities	4
	Other deferred debits and other assets	4	Other deferred credits and other liabilities	4
Total		$42		$9
As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate contracts	Prepayments and other	$42	Other current liabilities	$70
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	36
Commodity contracts	Prepayments and other	1	Other current liabilities	4
Total		$74		$110
Derivatives not designated as hedging instruments				
Commodity contracts	Prepayments and other	$1		
Energy management contracts	Prepayments and other	7	Prepayments and other	$1
	Other deferred debits and other assets	6	Other current liabilities	6
			Other deferred debits and other assets	6
Total		$14		$13

The effect of derivative instruments on the consolidated statements of income is as follows:

Fair Value Hedges

With regard to interest rate swaps designated as fair value hedges, any gains or losses related to the swaps or the fixed rate debt are recognized in current earnings within interest expense. The Company had no interest rate swaps designated as fair value hedges for any period presented, and the amortization of deferred gains on previously terminated swaps were not significant during any period presented.

Cash Flow Hedges

Derivatives in Cash Flow Hedging Relationships

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)	Loss Reclassified from Deferred Accounts into Income (Effective Portion) Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$106	Interest expense	$(3)
Year Ended December 31, 2012			
Interest rate contracts	$84	Interest expense	$(3)
Year Ended December 31, 2011			
Interest rate contracts	$(76)	Interest expense	$(3)

Millions of dollars	Gain or (Loss) Recognized in OCI, net of tax (Effective Portion)	Loss Reclassified from Accumulated OCI into Income, net of tax (Effective Portion) Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$ 5	Interest expense	$(8)
Commodity contracts	2	Gas purchased for resale	(3)
Total	$ 7		$(11)
Year Ended December 31, 2012			
Interest rate contracts	$ (4)	Interest expense	$(6)
Commodity contracts	(4)	Gas purchased for resale	(13)
Total	$ (8)		$(19)
Year Ended December 31, 2011			
Interest rate contracts	$ (42)	Interest expense	$(4)
Commodity contracts	(16)	Gas purchased for resale	(9)
Total	$ (58)		$(13)

As of December 31, 2013, the Company expects that during the next 12 months reclassifications from accumulated other comprehensive loss to earnings arising from cash flow hedges will include approximately $1.0 million as an increase to gas cost and approximately $7.0 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of December 31, 2013, all of the Company's commodity cash flow hedges settle by their terms before the end of 2016.

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in 2013 and 2012 and were $(1.1) million, net of tax, in 2011. These amounts are recorded within interest expense on the consolidated statements of income.

Derivatives Not Designated as Hedging Instruments

Millions of dollars	Loss Recognized in Income Location	Year Ended December 31, 2013	2012	2011
Commodity contracts	Gas purchased for resale	—	$(1)	$(2)

Millions of dollars	Gain or (Loss) Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$39	Other income	$50
Year Ended December 31, 2012			
Interest rate contracts	$—		$—
Year Ended December 31, 2011			
Interest rate contracts	$—		$—

The gains reclassified to other income of $50 million offset revenue reductions as previously described herein and in Note 2.

Credit Risk Considerations

The Company limits credit risk in its commodity and interest rate derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, the Company uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. The Company uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with the Company's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of the Company’s derivative instruments contain contingent provisions that require the Company to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2013 and 2012, the Company had posted $26.8 million and $78.3 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months is recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and 2012, the Company would have been required to post an additional $0.0 million and $26.2 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2013 and 2012, are $25.2 million and $104.5 million, respectively.

In addition, as of December 31, 2013 and December 31, 2012, the Company has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and December 31, 2012, the Company could request $34.1 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2013 and December 31, 2012 is $34.1 million and $32.1 million, respectively. In addition, at December 31, 2013, the Company could have called on letters of credit in the amount of $6 million related to $6 million in commodity derivatives that are in a net asset position, compared to letters of credit of $10 million related to derivatives of $13 million at December 31, 2012, if all the contingent features underlying these instruments had been fully triggered.

Information related to the Company's offsetting derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2013						
Interest rate	$32	—	$32	$(1)	—	$31
Commodity	4	—	4	—	—	4
Energy Management	8	—	8	—	—	8
Total	$44	—	$44	$(1)	—	$43
Balance sheet location	Prepayments and other		$21			
	Other deferred debits and other assets		23			
	Total		$44			
As of December 31, 2012						
Interest rate	$73	—	$73	$(17)	—	$56
Commodity	2	—	2	—	—	2
Energy Management	13	$(1)	12	—	—	12
Total	$88	$(1)	$87	$(17)	—	$70
Balance sheet location	Prepayments and other		$50			
	Other deferred debits and other assets		37			
	Total		$87			

Information related to the Company's offsetting derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$20	—	$20	$(1)	$19	—
Energy Management	8	—	8	—	6	$2
Total	$28	—	$28	$(1)	$25	$2
Balance sheet location	Other current liabilities		$10			
			18			

Other deferred credits and other liabilities	
Total	$28

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Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position: Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2012						
Interest rate	$106	—	$106	$(17)	$67	$22
Commodity	4	—	4	—	—	4
Energy Management	13	$(1)	12	—	11	1
Total	$123	$(1)	$122	$(17)	$78	$27

Balance sheet location	Other current liabilities	$80
	Other deferred credits and other liabilities	42
	Total	$122

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

The Company values available for sale securities using quoted prices from a national stock exchange, such as the NASDAQ, where the securities are actively traded. For commodity derivative and energy management assets and liabilities, the Company uses unadjusted NYMEX prices to determine fair value, and considers such measures of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. The Company's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	As of December 31, 2013		As of December 31, 2012	
Millions of dollars	Level 1	Level 2	Level 1	Level 2
Assets:				
Available for sale securities	$9	—	$6	—
Interest rate contracts	—	$32	—	$73
Commodity contracts	2	2	1	1
Energy management contracts	1	7	—	13
Liabilities:				
Interest rate contracts	—	20	—	106
Commodity contracts	—	—	—	4
Energy management contracts	—	12	1	15

There were no Level 3 fair value measurements for either period presented, and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2013 and December 31, 2012 were as follows:

	As of December 31, 2013		As of December 31, 2012	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value

Long-term debt	$5,449.3	$5,916.3	$5,121.0	$6,115.0

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

The Company sponsors a noncontributory defined benefit pension plan covering substantially all regular, full-time employees hired before January 1, 2014. In the third quarter of 2013, the Company amended its pension plan such that benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. The Company’s policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The Company’s pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all employees hired from January 1, 2000 through December 31, 2013. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee’s average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, the Company provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them. The Company provides life insurance benefits to retirees at no charge, except that employees hired after December 31, 2010 are ineligible for retiree life insurance benefits. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2013	2012	2013	2012
Benefit obligation, January 1	$931.6	$830.1	$265.3	$226.1
Service cost	21.8	19.6	5.9	4.8
Interest cost	38.5	43.0	11.1	11.9
Plan participants’ contributions	—	—	2.6	2.9
Actuarial (gain) loss	(83.4)	96.5	(35.1)	33.4
Benefits paid	(60.0)	(57.6)	(11.8)	(13.8)
Curtailment	(25.5)	—	—	—

Benefit obligation, December 31	$823.0	$931.6	$238.0	$265.3

The accumulated benefit obligation for pension benefits was $796.4 million at the end of 2013 and $874.6 million at the end of 2012. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Annual discount rate used to determine benefit obligation	5.03%	4.10%	5.19%	4.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.75%	3.75%	3.75%

A 7.4% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation at December 31, 2013 by $1.3 million and 2012 by $1.7 million. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation at December 31, 2013 by $1.2 million and 2012 by $1.5 million.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Fair value of plan assets	$870.0	$799.1	—	—
Benefit obligation	823.0	931.6	$238.0	$265.3
Funded status	$47.0	$(132.5)	$(238.0)	$(265.3)

Amounts recognized on the consolidated balance sheets consist of:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Current liability	—	—	$(11.5)	$(11.0)
Noncurrent asset	$47.0	—	—	—
Noncurrent liability	—	$(132.5)	(226.5)	(254.3)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$5.2	$10.7	$1.7	$3.7
Prior service cost	0.5	1.0	0.1	0.1
Transition obligation	—	—	—	0.1
Total	$5.7	$11.7	$1.8	$3.9

Amounts recognized in regulatory assets as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$124.8	$297.0	$24.4	$57.0
Prior service cost	12.8	26.9	0.9	1.5
Transition obligation	—	—	—	0.2
Total	$137.6	$323.9	$25.3	$58.7

In connection with the joint ownership of Summer Station, as of December 31, 2013 and 2012, the Company recorded within deferred debits $14.1 million and $26.8 million, respectively, attributable to Santee Cooper's portion of shared pension

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costs. As of December 31, 2013 and 2012, the Company also recorded within deferred debits $12.6 million and $14.7 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2013	2012
Fair value of plan assets, January 1	$799.1	$755.0
Actual return on plan assets	130.9	101.7
Benefits paid	(60.0)	(57.6)
Fair value of plan assets, December 31	$870.0	$799.1

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, the Company adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The Company’s pension plan asset allocation at December 31, 2013 and 2012 and the target allocation for 2014 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2014	2013	2012
Equity Securities	58 %	59 %	66 %
Fixed Income	33 %	32 %	25 %
Hedge Funds	9 %	9 %	9 %

For 2014, the expected long-term rate of return on assets will be 8.00%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan’s historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment policy adopted for 2014.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2013 and 2012, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using							
Millions of dollars	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	December 31, 2013				December 31, 2012			
Common stock	$332	$332			$319	$319		
Preferred stock	1	1			1	1		
Mutual funds	305	20	$285		246	12	$234	
Short-term investment vehicles	19		19		20		20	
US Treasury securities	33		33		42		42	
Corporate debt securities	53		53		56		56	
Loans secured by mortgages	12		12		11		11	
Municipals	4		4		4		4	
Limited partnerships	35	1	34		30	1	29	
Multi strategy hedge funds	76			$76	70			$70
	$870	$354	$440	$76	$799	$333	$396	$70

There were no transfers of fair value amounts into or out of Level 1, 2 or 3 during 2013 or 2012.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements	
	Level 3	
Millions of dollars	2013	2012
Beginning Balance	$70	$65
Unrealized gains included in changes in net assets	6	5
Purchases, issuances, and settlements	—	—
Ending Balance	$76	$70

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from the Company’s assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2014	$61.5	$11.7
2015	61.2	12.6
2016	63.8	13.4
2017	65.8	14.1
2018	66.1	14.7
2019-2023	338.4	82.4

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, the Company does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

The Company records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Service cost	$21.8	$19.6	$18.3	$5.9	$4.8	$4.3
Interest cost	38.5	43.0	43.5	11.1	11.9	12.2
Expected return on assets	(61.4)	(59.5)	(63.7)	n/a	n/a	n/a
Prior service cost amortization	6.0	7.0	7.0	0.7	0.9	1.0
Amortization of actuarial losses	16.9	18.4	12.2	3.3	1.4	0.4
Transition obligation amortization	—	—	—	0.3	0.7	0.7
Curtailment loss	9.9	—	—	—	—	—
Net periodic benefit cost	$31.7	$28.5	$17.3	$21.3	$19.7	$18.6

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension cost related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension costs related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2).

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Current year actuarial (gain) loss	$(5.0)	$1.7	$2.9	$(1.8)	$2.0	$0.4
Amortization of actuarial losses	(0.5)	(0.6)	(0.4)	(0.2)	—	—
Amortization of prior service cost	(0.2)	(0.2)	(0.2)	—	—	(0.1)
Prior service cost (credit)	(0.3)	—	—	—	—	—
Amortization of transition obligation	—	—	—	(0.1)	(0.1)	(0.1)
Total recognized in other comprehensive income	$(6.0)	$0.9	$2.3	$(2.1)	$1.9	$0.2

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Current year actuarial (gain) loss	$(157.5)	$45.0	$70.9	$(29.9)	$31.4	$6.0
Amortization of actuarial losses	(14.7)	(16.0)	(10.6)	(2.7)	(1.2)	(0.3)
Amortization of prior service cost	(5.2)	(6.4)	(6.4)	(0.6)	(0.8)	(0.9)
Prior service cost (credit)	(8.9)	—	—	—	—	—
Amortization of transition obligation	—	—	—	(0.2)	(0.5)	(0.5)
Total recognized in regulatory assets	$(186.3)	$22.6	$53.9	$(33.4)	$28.9	$4.3

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.10%/5.07%	5.25%	5.56%	4.19%	5.35%	5.72%
Expected return on plan assets	8.00%	8.25%	8.25%	n/a	n/a	n/a
Rate of compensation increase	3.75%/3.00%	4.00%	4.00%	3.75%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	7.80%	8.20%	8.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2020	2020	2017

Net periodic benefit cost for the period through September 1, 2013 was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The estimated amounts to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits

		Other Postretirement Benefits
Actuarial loss	$0.2	—
Prior service cost	0.1	—
Total	$0.3	—

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$4.3	$0.4
Prior service cost	3.5	0.3
Total	$7.8	$0.7

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

The Company sponsors a defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. The Company provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan for 2013, 2012 and 2011 were $23.4 million, $22.3 million and $21.8 million, respectively, and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

The LTECP provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation costs related to share-based payment transactions are required to be recognized in the financial statements. With limited exceptions, including those liability awards discussed below, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2011-2013, 2012-2014 and 2013-2015 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three -year performance cycle. In each of the performance cycles, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of retirement or termination of employment prior to the end of the cycle, subject to exceptions for death, disability or change in control. The remaining 80% of the award was granted in performance shares. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA’s performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in “GAAP-adjusted net earnings per share from operations” (weighted 50%).

Compensation cost of liability awards is recognized over their respective three -year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2011-2013 performance cycle were paid in cash at SCANA’s discretion in February 2014. Cash-settled liabilities related to prior program cycles were paid totaling $12.2 million in 2013, $11.8 million in 2012, and $13.6 million in 2011.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling $8.7 million in 2013, $15.0 million in 2012 and $6.1 million in 2011. Fair value adjustments resulted in capitalized compensation costs of $1.4 million in 2013, $2.7 million in 2012 and $0.9 million in 2011.

Equity Awards

No equity awards were made during any period presented, and the effects of previous such awards on the Company's results of operations, cash flows and financial position were not significant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company’s nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G’s maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder’s risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer’s losses. Based on the current annual premiums, SCE&G’s portion of the retrospective premium assessment would not exceed $41.6 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Company’s results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. Under the terms of the agreement SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in a revised rates filing under the BLRA.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules

CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that the revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New

Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification.

Environmental

SCE&G

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. The Company is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. The Company also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on the Company, if any. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCANA, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed the Company to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. The Company will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and the Company's evaluation of the rule is ongoing. The Company's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in the Company's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. The Company is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of the Company. The Company believes that any additional costs imposed by such regulations would be recoverable through rates.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While the Company cannot predict how extensive the regulations will be, the Company believes that any additional costs imposed by such regulations would be recoverable through rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the states of South Carolina and North Carolina have similar laws. The Company maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify the Company that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $20.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

PSNC Energy

PSNC Energy is responsible for environmental clean-up at five sites in North Carolina on which MGP residuals are present or suspected. Actual remediation costs for these sites will depend on a number of factors, such as actual site conditions, third-party claims and recoveries from other PRPs. PSNC Energy has recorded a liability and associated regulatory asset of approximately $2.8 million, the estimated remaining liability at December 31, 2013. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

Claims and Litigation

The Company is engaged in various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on the Company's results of operations, cash flows or financial condition.

Operating Lease Commitments

The Company is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $14.8 million in 2013, $14.8 million in 2012 and $15.8 million in 2011. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2014	$ 7
2015	6
2016	4
2017	2
2018	1
Thereafter	21
Total	$ 41

Guarantees

SCANA issues guarantees on behalf of its consolidated subsidiaries to facilitate commercial transactions with third parties. These guarantees are in the form of performance guarantees, primarily for the purchase and transportation of natural gas, standby letters of credit issued by financial institutions and credit support for certain tax-exempt bond issues. SCANA is not required to recognize a liability for such guarantees unless it becomes probable that performance under the guarantees will be required. SCANA believes the likelihood that it would be required to perform or otherwise incur any losses associated with these guarantees is remote; therefore, no liability for these guarantees has been recognized. To the extent that a liability subject to a guarantee has been incurred, the liability is included in the consolidated financial statements. At December 31, 2013, the maximum future payments (undiscounted) that SCANA could be required to make under guarantees totaled approximately $1.6 billion.

Asset Retirement Obligations

The Company recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that results from their acquisition, construction, development and normal operation relate primarily to the Company's regulated utility operations. As of December 31, 2013, the Company has recorded AROs of approximately $191 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $385 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2013	2012
Beginning balance	$561	$473
Liabilities incurred	6	—
Liabilities settled	(4)	(5)
Accretion expense	25	24
Revisions in estimated cash flows	(12)	69
Ending balance	$576	$561

11. AFFILIATED TRANSACTIONS

The Company received cash distributions from equity-method investees of $10.4 million in 2013, $12.5 million in 2012 and $5.5 million in 2011 . The Company made investments in equity-method investees of $5.2 million in 2013, $10.6 million in 2012 and $13.6 million in 2011.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's payable to this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's total purchases from this affiliate were $134.2 million in 2013 and $111.6 million in 2012. SCE&G's total sales to this affiliate were $133.6 million in 2013 and $111.1 million in 2012.

12. SEGMENT OF BUSINESS INFORMATION

Reportable segments, which are described below, follow the same accounting policies as those described in Note 1. The Company records intersegment sales and transfers of electricity and gas based on rates established by the appropriate regulatory authority. Nonregulated sales and transfers are recorded at current market prices.

Electric Operations is primarily engaged in the generation, transmission and distribution of electricity, and is regulated by the SCPSC and FERC.

Gas Distribution, comprised of the local distribution operations of SCE&G and PSNC Energy, is engaged in the purchase and sale, primarily at retail, of natural gas. SCE&G and PSNC Energy are regulated by the SCPSC and the NCUC, respectively.

Retail Gas Marketing markets natural gas in Georgia and is regulated as a marketer by the GPSC. Energy Marketing markets natural gas to industrial and large commercial customers and municipalities, primarily in the Southeast.

All Other is comprised of other direct and indirect wholly-owned subsidiaries of the Company. One of these subsidiaries operates a FERC-regulated interstate pipeline company and the other subsidiaries conduct nonregulated operations in energy-related and telecommunications industries. None of these subsidiaries met the quantitative thresholds for determining reportable segments during any period reported.

Regulated reportable segments share a similar regulatory environment and, in some cases, overlapping service areas. However, Electric Operations' product differs from the other segments, as does its generation process and method of distribution. The marketing segments differ from each other in their respective markets and customer type.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Retail Gas Marketing	Energy Marketing	All Other	Adjustments/ Eliminations	Consolidated Total
2013							
External Revenue	$2,423	$942	$465	$652	$40	$ (27)	$4,495
Intersegment Revenue	6	1	—	167	416	(590)	—
Operating Income	679	153	—	n/a	27	51	910
Interest Expense	19	22	1	—	4	251	297
Depreciation and Amortization	297	70	3	—	26	(18)	378
Income Tax Expense	6	33	15	4	14	151	223
Net Income	n/a	n/a	24	6	(2)	443	471
Segment Assets	9,488	2,340	172	133	1,378	1,653	15,164
Expenditures for Assets	907	140	—	1	31	27	1,106
Deferred Tax Assets	10	27	8	2	14	(61)	—
2012							
External Revenue	$2,446	$764	$413	$543	$45	$ (35)	$4,176
Intersegment Revenue	7	1	—	125	416	(549)	—
Operating Income	668	141	n/a	n/a	22	28	859
Interest Expense	21	23	1	—	3	247	295
Depreciation and Amortization	278	67	3	—	25	(17)	356
Income Tax Expense	7	32	7	3	15	118	182
Net Income	n/a	n/a	11	5	1	403	420
Segment Assets	8,989	2,292	153	122	1,415	1,645	14,616
Expenditures for Assets	999	123	—	1	14	(60)	1,077
Deferred Tax Assets	9	26	10	4	17	(55)	11
2011							
External Revenue	$2,424	$840	$479	$657	$41	$ (32)	$4,409
Intersegment Revenue	8	1	—	188	406	(603)	—
Operating Income	616	132	n/a	n/a	18	47	813
Interest Expense	23	24	1	—	3	233	284
Depreciation and Amortization	271	65	3	—	25	(18)	346
Income Tax Expense	5	30	16	3	10	104	168
Net Income	n/a	n/a	24	4	(6)	365	387
Segment Assets	8,222	2,179	185	114	1,377	1,457	13,534
Expenditures for Assets	806	140	—	1	17	(18)	946
Deferred Tax Assets	9	12	9	9	17	(30)	26

Management uses operating income to measure segment profitability for SCE&G and other regulated operations and evaluates utility plant, net, for segments attributable to SCE&G. As a result, the Company does not allocate interest charges, income tax expense or assets other than utility plant to its segments. For nonregulated operations, management uses net income as the measure of segment profitability and evaluates total assets for financial position. Interest income is not reported by segment and is not material. The Company's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the energy-related and regulated segments. Revenues from non-reportable and nonregulated segments are included in Other Income. Therefore the adjustments to total operating revenues remove revenues from non-reportable segments. Adjustments to net income consist of the unallocated net income of the Company's regulated reportable segments.

Segment Assets include utility plant, net for SCE&G's Electric Operations and Gas Distribution, and all assets for PSNC Energy and the remaining segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for SCE&G.

Adjustments to Interest Expense, Income Tax Expense, Expenditures for Assets and Deferred Tax Assets include primarily the totals from SCANA or SCE&G that are not allocated to the segments. Interest Expense is also adjusted to eliminate charges between affiliates. Adjustments to Depreciation and Amortization consist of non-reportable segment expenses, which are not included in the depreciation and amortization reported on a consolidated basis. Expenditures for Assets are adjusted for AFC and revisions to estimated cash flows related to asset retirement obligations. Deferred Tax Assets are adjusted to net them against deferred tax liabilities on a consolidated basis.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars, except per share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2013					
Total operating revenues	$1,311	$1,016	$1,051	$1,117	$4,495
Operating income	293	189	255	173	910
Net income	151	85	131	104	471
Basic earnings per share	1.13	.60	.94	.73	3.40
Diluted earnings per share	1.11	.60	.94	.73	3.39
2012					
Total operating revenues	$1,107	$908	$1,038	$1,123	$4,176
Operating income	238	171	238	212	859
Net income	121	72	122	105	420
Basic earnings per share	.93	.55	.93	.79	3.20
Diluted earnings per share	.91	.54	.91	.78	3.15

SOUTH CAROLINA ELECTRIC & GAS COMPANY

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

SCE&G is a regulated public utility engaged in the generation, transmission, distribution and sale of electricity and in the purchase and sale, primarily at retail, and transportation of natural gas. SCE&G’s business is subject to seasonal fluctuations. Generally, sales of electricity are higher during the summer and winter months because of air-conditioning and heating requirements, and sales of natural gas are greater in the winter months due to heating requirements. SCE&G’s electric service territory extends into 24 counties covering nearly 17,000 square miles in the central, southern and southwestern portions of South Carolina. The service area for natural gas encompasses all or part of 35 counties in South Carolina and covers approximately 22,600 square miles.

Key Earnings Drivers and Outlook

During 2013, economic growth continued to improve in the southeast. Significant industrial announcements in SCE&G’s service territory were made during the year, and announcements made in previous years began to materialize. In addition, the Port of Charleston continues to see increased traffic, with container volume up 5.7% over 2012. SCE&G’s residential and commercial customer growth rates also were positive. At December 31, 2013, a preliminary estimate of seasonally adjusted unemployment for South Carolina was 6.6%. Though improved from the 8.6% unemployment rate at December 31, 2012, the improvement may be due in part to people leaving the workforce. Nationwide the civilian labor force was 62.8% at December 31, 2013, matching a 35-year low.

Over the next five years, key earnings drivers for SCE&G will be additions to utility rate base, consisting primarily of capital expenditures for new generating capacity, environmental facilities and system expansion. Other factors that will impact future earnings growth include the regulatory environment, customer growth and usage and the level of growth of operation and maintenance expenses and taxes.

Electric Operations

The electric operations segment is comprised of the electric operations of SCE&G, GENCO and Fuel Company, and is primarily engaged in the generation, transmission, distribution and sale of electricity in South Carolina. At December 31, 2013 SCE&G provided electricity to approximately 678,000 customers. GENCO owns a coal-fired generating station and sells electricity solely to SCE&G. Fuel Company acquires, owns, provides financing for and sells at cost to SCE&G nuclear fuel, certain fossil fuels and emission and other environmental allowances.

Operating results for electric operations are primarily driven by customer demand for electricity, rates allowed to be charged to customers and the ability to control growth in costs. Through 2013, the effect of weather on operating results was largely mitigated by the eWNA; however, the eWNA was discontinued pursuant to an SCPSC order effective with the first billing cycle of January 2014. Embedded in the rates charged to customers is an allowed regulatory return on equity. SCE&G’s allowed return on equity in 2013 was 10.25% for non-BLRA expenditures, and 11.0% for BLRA-related expenditures. As further described in Note 2 to the consolidated financial statements, SCE&G's allowed return on equity for non-BLRA expenditures was 10.7% prior to 2013. Demand for electricity is primarily affected by weather, customer growth and the economy. SCE&G is able to recover the cost of fuel used in electric generation through retail customers’ bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units have an aggregate generating capacity (2012 summer rating) of 730 MW. As of December 31, 2013, three of these units have been retired. For additional information, see Note 1 and Note 2 to the consolidated financial statements.

New Nuclear Construction

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

SCE&G expects Unit 2 to be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest.

Significant recent developments in new nuclear construction include the following:

- In the first quarter of 2013, initial pouring of the Unit 2 nuclear island basemat was completed. The basemat provides a foundation for the containment vessel, shield building and auxiliary building that make up the nuclear island. The Unit 3 nuclear island basemat was completed in the fourth quarter of 2013.

- In April 2013, the 500-ton CR-10 module was set on the Unit 2 basemat. CR-10 supports the containment vessel. Construction of Unit 3's CR-10 module is currently underway.

- In May 2013, the containment vessel bottom head for Unit 2 was put in place. The containment vessel will house numerous reactor system components, such as the reactor vessel, steam generator and pressurizer. Work continues in building containment vessel rings that will be placed on the containment vessel bottom head for Unit 2.

- In September 2013, the reactor vessel cavity for Unit 2 (CA-04 module) was placed in the containment vessel bottom head. The reactor vessel cavity will house the reactor vessel, which in turn will house the fuel assemblies. The reactor vessel for Unit 2 is on-site.

- Fabrication has begun for Unit 2's steam generator and refueling canal module (CA-01 module) that will be located inside the containment vessel.

- Ring 1 of the Unit 2 containment vessel is scheduled to be placed on the containment vessel bottom head in the second quarter 2014. Ring 2 is scheduled to be placed in the fourth quarter of 2014.

- While progress has been made with production, quality assurance and quality control issues, the schedule for fabrication of sub-modules at the contractor facility remains a focus area for the project.

- During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

For additional information on these and other matters, see New Nuclear Construction Matters herein and Note 2 and Note 10 to the consolidated financial statements.

Environmental

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. New federal effluent limitation guidelines for steam electric generating units were published in the Federal Register on June 7, 2013, and the ELG Rule is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020. Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014, and Congress is expected to consider further amendments to the CWA.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 14, 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO.

The above environmental initiatives and other similar issues are described in Environmental Matters herein and in Note 10 to the consolidated financial statements. Unless otherwise noted, Consolidated SCE&G cannot predict when regulatory rules or legislative requirements for any of these initiatives will become final, if at all, or what conditions they may impose on it, if any. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Gas Distribution

The Gas Distribution segment, comprised of the local distribution operations of SCE&G, is primarily engaged in the purchase, transportation and sale of natural gas to retail customers in portions of South Carolina. At December 31, 2013 this segment provided natural gas to approximately 329,000 customers.

Operating results for gas distribution are primarily influenced by customer demand for natural gas, rates allowed to be charged to customers and the ability to control growth in costs. Embedded in the rates charged to customers is an allowed regulatory return on equity of 10.25%.

Demand for natural gas is primarily affected by weather, customer growth, the economy and the availability and price of alternate fuels. Natural gas competes with electricity, propane and heating oil to serve the heating and, to a lesser extent, other household energy needs of residential and small commercial customers. This competition is generally based on price and convenience. Large commercial and industrial customers often have the ability to switch from natural gas to an alternate fuel, such as propane or fuel oil. Natural gas competes with these alternate fuels based on price. As a result, any significant disparity between supply and demand, either of natural gas or of alternate fuels, and due either to production or delivery disruptions or other factors, will affect price and will impact SCE&G’s ability to retain large commercial and industrial customers. In addition, the production of shale gas in the United States has resulted in significantly lower prices for this commodity, and such prices are expected to continue for the foreseeable future.

RESULTS OF OPERATIONS

Net Income

Net income for Consolidated SCE&G was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Net income	$390.8	11.0 %	$352.0	11.4 %	$316.1

2013 vs 2012	Net income increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.
2012 vs 2011	Net income increased due to higher electric and gas margins. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher property taxes and higher interest expense, further described below.

Dividends Declared

Consolidated SCE&G's Boards of Directors declared the following dividends on common stock (all of which was held by SCANA) during 2013 and 2012:

Declaration Date	Dividend Amount	Quarter Ended	Payment Date
February 20, 2013	$64.0 million	March 31, 2013	April 1, 2013
April 25, 2013	$63.8 million	June 30, 2013	July 1, 2013
July 31, 2013	$67.5 million	September 30, 2013	October 1, 2013
October 31, 2013	$61.7 million	December 31, 2013	January 1, 2014
February 15, 2012	$53.4 million	March 31, 2012	April 1, 2012
May 3, 2012	$54.1 million	June 30, 2012	July 1, 2012
August 2, 2012	$55.8 million	September 30, 2012	October 1, 2012
October 24, 2012	$45.6 million	December 31, 2012	January 1, 2013

When a dividend payment date falls on a weekend or holiday, the payment is made the following business day.

Electric Operations

Electric Operations is comprised of the electric operations of SCE&G, GENCO and Fuel Company. Electric operations sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$2,430.5	(0.9)%	$2,453.1	0.9%	$2,432.2
Less: Fuel used in generation	751.0	(11.0)%	844.2	(8.5)%	922.5
Purchased power	43.0	53.0%	28.1	46.4%	19.2
Margin	$1,636.5	3.5%	$1,580.8	6.1%	$1,490.5

2013 vs 2012	Margin increased primarily due to base rate increases under the BLRA of $54.2 million and higher electric base rates of $67.3 million approved in the December 2012 rate order. Additionally, pursuant to accounting orders of the SCPSC, 2013's electric margin reflects downward adjustments of $50.1 million to revenue. Such adjustments are fully offset by the recognition within other income of gains realized upon the settlement of certain derivative interest rate contracts, which had been deferred as regulatory liabilities. See Note 2 to the consolidated financial statements.
2012 vs 2011	Margin increased primarily by $54.4 million due to an increase in retail electric base rates approved by the SCPSC under the BLRA, by $3.7 million due to customer growth and by $11.0 million due to the expiration of a decrement rider approved in the 2010 retail electric base rate case.

Sales volumes (in GWh) related to the electric margin above, by class, were as follows:

Classification	2013	Change	2012	Change	2011
Residential	7,571	—	7,571	(8.0)%	8,232
Commercial	7,205	(1.2)%	7,291	(1.4)%	7,397
Industrial	6,000	2.8%	5,836	(1.7)%	5,938
Other	581	(0.9)%	586	2.4%	572
Total retail sales	21,357	0.3%	21,284	(3.9)%	22,139
Wholesale	955	(63.2)%	2,595	26.6%	2,049
Total	22,312	(6.6)%	23,879	(1.3)%	24,188

2013 vs 2012 Retail sales volume increased primarily due to customer growth and the effects of weather, partially offset by lower average use. The decrease in wholesale sales is primarily due to the expiration of two customer contracts.

2012 vs 2011 Retail sales volume decreased by 983 GWh primarily due to the effects of milder weather. The increase in wholesale sales is primarily due to higher contract utilization by a wholesale customer.

Gas Distribution

Gas Distribution is comprised of the local distribution operations of SCE&G. Gas distribution sales margin (including transactions with affiliates) was as follows:

Millions of dollars	2013	Change	2012	Change	2011
Operating revenues	$414.4	16.5%	$355.6	(8.2)%	$387.4
Less: Gas purchased for resale	244.1	24.2%	196.6	(18.0)%	239.7
Margin	$170.3	7.1%	$159.0	7.7%	$147.7

2013 vs 2012 Margin increased primarily due to the SCPSC-approved increase in base rates under the RSA which became effective with the first billing cycle of November 2012, as well as residential and commercial customer growth.

2012 vs 2011 Margin increased $8.3 million due to the SCPSC-approved increases in retail gas base rates under the RSA which became effective with the first billing cycles of November 2011 and 2012.

Sales volumes (in MMBTU) by class, including transportation gas, were as follows:

Classification (in thousands)	2013	Change	2012	Change	2011
Residential	12,515	23.3%	10,153	(13.0)%	11,674
Commercial	12,786	9.1%	11,723	(2.9)%	12,071
Industrial	20,411	5.5%	19,341	14.0%	16,963
Transportation gas	4,801	2.0%	4,707	7.6%	4,376
Total	50,513	10.0%	45,924	1.9%	45,084

2013 vs 2012 Total sales volumes increased primarily due to customer growth, increased industrial usage and the effects of weather.

2012 vs 2011 Residential and commercial sales volume decreased primarily due to milder weather. Industrial and transportation sales volumes increased due to the competitive price of gas versus alternate fuel sources.

Other Operating Expenses

Other operating expenses were as follows:

Millions of dollars	2013	Change		2012	Change		2011
Other operation and maintenance	$556.5	2.8	%	$541.6	5.1	%	$515.1
Depreciation and amortization	313.4	6.8	%	293.4	2.6	%	286.1
Other taxes	200.2	6.3	%	188.3	3.2	%	182.5

2013 vs 2012	Other operation and maintenance expenses increased by $16.7 million due to incremental expenses associated with the December 2012 SCPSC rate order and by $5.7 million due to higher electric generation, transmission and distribution expenses. These increases were partially offset by lower compensation costs of $10.1 million due to reduced headcount and lower incentive compensation accruals and by other general expenses. Depreciation and amortization expense increased $13.2 million due to the recognition of depreciation expense associated with the Wateree Station scrubber which was provided for in the December 2012 SCPSC rate order and due to other net plant additions. Other taxes increased primarily due to higher property taxes on net property additions.
2012 vs 2011	Other operation and maintenance expenses increased by $9.3 million due to higher generation, transmission and distribution expenses, by $1.7 million due to higher general expenses and by $14.2 million due to higher incentive compensation and other benefits. Depreciation and amortization expense increased primarily due to net property additions. Other taxes increased primarily due to higher property taxes on net property additions.

Net Periodic Benefit Cost

Net periodic benefit cost was recorded on Consolidated SCE&G's income statements and balance sheets as follows:

Millions of dollars	2013	Change		2012	Change		2011
Income Statement Impact:							
Employee benefit costs	$11.0	100.0%		—	—		—
Other expense	0.6	50.0	%	$0.4	100.0	%	$0.2
Balance Sheet Impact:							
Increase in capital expenditures	6.4	12.3	%	5.7	67.6	%	3.4
Component of amount receivable from Summer Station co-owner	2.5	13.6	%	2.2	83.3	%	1.2
Increase in regulatory asset	5.5	(63.3	)%	15.0	64.8	%	9.1
Net periodic benefit cost	$26.0	11.6	%	$23.3	67.6	%	$13.9

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension costs related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension cost related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2 to the consolidated financial statements). In 2013, such amortizations totaled approximately $2.0 million for electric operations and $0.2 million for gas operations.

Other Income (Expense)

Other income (expense) includes the results of certain non-utility activities. Components of other income (expense), were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Other income	$52.7	*	$0.4	(91.8)%	$4.9
Other expense	(17.5)	(2.2)%	(17.9)	51.7 %	(11.8)
Total	$35.2	*	$(17.5)	*	$(6.9)

* Greater than 100%

2013 vs 2012: Total other income (expense) increased primarily due to the recognition, pursuant to SCPSC accounting orders, of $50.1 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as regulatory liabilities. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

2012 vs 2011: Total other income (expense) decreased primarily due to higher non-utility related employee benefit costs in 2012.

AFC

AFC is a utility accounting practice whereby a portion of the cost of both equity and borrowed funds used to finance construction (which is shown on the balance sheet as construction work in progress) is capitalized. Consolidated SCE&G includes an equity portion of AFC in nonoperating income and a debt portion of AFC in interest charges (credits) as noncash items, both of which have the effect of increasing reported net income. AFC represented approximately 6.6% of income before income taxes in 2013, 6.3% in 2012 and 4.5% in 2011, respectively.

Interest Expense

Components of interest expense, net of the debt component of AFC, were as follows:

Millions of dollars	2013	Change	2012	Change	2011
Interest on long-term debt, net	$206.8	3.0 %	$200.7	5.1 %	$191.0
Other interest expense	10.5	7.1 %	9.8	(27.4)%	13.5
Total	$217.3	3.2 %	$210.5	2.9 %	$204.5

Interest on long-term debt increased in each year primarily due to increased long-term borrowings. Other interest expense increased in 2013 and decreased in 2012, primarily due to reductions in principal balances outstanding on short-term debt over the respective prior year and also decreased in 2012 due to the reversal in 2012 of interest which had been accrued in 2011 related to a tax uncertainty that was resolved (see Note 5 to the consolidated financial statements).

Income Taxes

Income tax expense increased in 2013 over 2012 and in 2012 over 2011 primarily due to increases in income before taxes. The increase in the effective tax rate in 2013 is principally attributable to lower recognition of EIZ Credits upon the completion of the amortization of certain such credits in 2012.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its contractual cash obligations will be met through internally generated funds and the incurrence of additional short- and long-term indebtedness. Consolidated SCE&G expects that, barring a future impairment of the capital markets, it has or can obtain adequate sources of financing to meet its projected cash requirements for the foreseeable future, including the cash requirements for nuclear construction and refinancing maturing long-term debt. Consolidated SCE&G's ratio of earnings to fixed charges for the year ended December 31, 2013 was 3.48.

Consolidated SCE&G’s cash requirements arise primarily from its operational needs, funding its construction programs and payment of dividends to SCANA. The ability of Consolidated SCE&G to replace existing plant investment, to expand to meet future demand for electricity and gas and to install equipment necessary to comply with environmental
regulations, will depend upon its ability to attract the necessary financial capital on reasonable terms. Consolidated SCE&G recovers the costs of providing services through rates charged to customers. Rates for regulated services are generally based on historical costs. As customer growth and inflation occur and Consolidated SCE&G continues its ongoing construction program, Consolidated SCE&G expects to seek increases in rates. Consolidated SCE&G’s future financial position and results of operations will be affected by Consolidated SCE&G’s ability to obtain adequate and timely rate and other regulatory relief.

Cash outlays for property additions and construction expenditures, including nuclear fuel, net of AFC were $1.0 billion in 2013 and are estimated to be $1.5 billion in 2014.

Consolidated SCE&G’s current estimates of its capital expenditures for construction and nuclear fuel for 2014-2016, which are subject to continuing review and adjustment, are as follows:

Estimated Capital Expenditures			
Millions of dollars	2014	2015	2016
Consolidated SCE&G - Normal			
Generation	$136	$145	$112
Transmission & Distribution	230	280	258
Other	14	25	19
Gas	50	51	73
Common	9	7	10
Total Consolidated SCE&G - Normal	439	508	472
New Nuclear (including transmission)	950	905	667
Cash Requirements for Construction	1,389	1,413	1,139
Nuclear Fuel	67	30	147
Total Estimated Capital Expenditures	$1,456	$1,443	$1,286

Estimated capital expenditures for Nuclear Fuel in 2016 include approximately $53 million, which is SCE&G's share of nuclear fuel it acquired in 2013. This fuel has been recorded in utility plant and the corresponding obligation has been recorded in long-term debt on the consolidated balance sheet.

Consolidated SCE&G’s contractual cash obligations as of December 31, 2013 are summarized as follows:

Contractual Cash Obligations					
	Payments due by period				
Millions of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	More than 5 years
Long-term and short-term debt including interest	$8,403	$510	$653	$1,090	$6,150
Capital leases	12	2	6	2	2
Operating leases	30	5	6	1	18
Purchase obligations	3,669	1,802	1,646	221	—
Other commercial commitments	2,524	527	713	571	713
Total	$14,638	$2,846	$3,024	$1,885	$6,883

Included in the table above in purchase obligations is SCE&G's portion of a contractual agreement for the design and construction of the New Units at the Summer Station site. SCE&G expects to be a joint owner and share operating costs and generation output of the New Units, with SCE&G currently responsible for 55 percent of the cost and receiving 55 percent of the output, and other joint owner (or owners) the remaining 45 percent. Also included in the table above is the estimated $500 million SCE&G expects it will cost to acquire an additional 5% ownership in the New Units as further described in New Nuclear Construction Matters.

Also included in purchase obligations are customary purchase orders under which SCE&G has the option to utilize certain vendors without the obligation to do so. SCE&G may terminate such arrangements without penalty.

Included in other commercial commitments are estimated obligations for coal and nuclear fuel purchases. SCE&G also has a legal obligation associated with the decommissioning and dismantling of Summer Station Unit 1 and other conditional asset retirement obligations that are not listed in the contractual cash obligations above. See Notes 1 and 10 to the consolidated financial statements.

At December 31, 2013, Consolidated SCE&G had posted $1.5 million in cash collateral for interest rate derivative contracts.

Financing Limits and Related Matters

Consolidated SCE&G’s issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by regulatory bodies including the SCPSC and FERC. Financing programs currently utilized by Consolidated SCE&G follow.

SCE&G has obtained FERC authority to issue short-term indebtedness and to assume liabilities as a guarantor(pursuant to Section 204 of the Federal Power Act). SCE&G may issue unsecured promissory notes, commercial paper and direct loans in amounts not to exceed $1.6 billion outstanding with maturity dates of one year or less, and may enter into guaranty agreements in favor of lenders, bankers, and dealers in commercial paper in amounts not to exceed $600 million. GENCO has obtained FERC authority to issue short-term indebtedness not to exceed $150 million outstanding with maturity dates of one year or less. The authority described herein will expire in October 2014.

In October 2013, the Consolidated SCE&G's existing committed LOCs were extended by one year. As a result, at December 31, 2013 SCE&G and Fuel Company were parties to five-year credit agreements in the amounts of $1.2 billion, (of which $500 million relates to Fuel Company) which expire in October 2018. In addition, at December 31, 2013 SCE&G was party to a three-year credit agreement in the amount of $200 million which expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. For a list of banks providing credit support and other information, see Note 4 to the consolidated financial statements.
As of December 31, 2013, Consolidated SCE&G had no outstanding borrowings under its $1.4 billion facilities, had approximately $251 million in commercial paper borrowings outstanding, was obligated under $0.3 million in LOC-supported letters of credit, and had approximately $92 million in cash and temporary investments. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing for repayment of the outstanding balance
on its draws, while maintaining appropriate levels of liquidity. Average short-term borrowings outstanding during 2013 were approximately $369 million. Short-term cash needs were met primarily through the issuance of commercial paper.

At December 31, 2013, Consolidated SCE&G’s long-term debt portfolio has a weighted average maturity of approximately 20 years and bears an average cost of 5.66%. Substantially all of Consolidated SCE&G's long-term debt bears fixed interest rates or is swapped to fixed. To further preserve liquidity, Consolidated SCE&G rigorously reviews its projected capital expenditures and operating costs and adjusts them where possible without impacting safety, reliability, and core customer service.

SCE&G's Restated Articles of Incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock, all of which is beneficially owned by SCANA.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013, approximately $63.1 million of retained earnings were restricted by this requirement as to payment of cash dividends on SCE&G's common stock.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Financing Activities

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.625% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027.

In November 2012, SCE&G repaid at maturity $4.4 million of 4.2% tax-exempt industrial revenue bonds, and repaid prior to maturity $29.2 million of 5.45% tax-exempt industrial revenue bonds due November 1, 2032.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042 (issued at a premium with a yield of 3.86%), which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds which were issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

During 2013 there were net cash inflows related to financing activities of $49 million primarily due to the issuance of long-term debt and contributions from parent, partially offset by repayment of short- and long-term debt and payment of dividends.

Investing Activities

SCE&G paid approximately $6 million, net, through the third quarter of 2013 to settle interest rate derivative contracts upon the issuance of long-term debt for contracts that had been designated as hedges.

In addition, during the fourth quarter of 2013, SCE&G received approximately $120 million upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt. Pursuant to SCPSC accounting orders, $50.1 million of such gains were recognized within other income, with such gain recognition being fully offset by downward adjustments to revenues reflected within electric margin.

In February 2014, Consolidated SCE&G's Boards of Directors declared dividends on common stock of $64.3 million, payable on April 1, 2014.

For additional information, see Note 4 to the consolidated financial statements.

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act included 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 and 50% bonus depreciation for property placed in service for 2012. The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation for property placed in service in 2013. These incentives, along with certain other deductions, have had a positive impact on the cash flows of Consolidated SCE&G.

ENVIRONMENTAL MATTERS

Consolidated SCE&G's operations are subject to extensive regulation by various federal and state authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes. Applicable statutes and rules include the CAA, CWA, Nuclear Waste Act and CERCLA, among others. Compliance with these environmental requirements involves significant capital and operating costs, which Consolidated SCE&G expects to recover through existing ratemaking provisions.

For the three years ended December 31, 2013, Consolidated SCE&G's capital expenditures for environmental control equipment at its fossil fuel generating stations totaled \$46.1 million. In addition, Consolidated SCE&G made expenditures to operate and maintain environmental control equipment at its fossil plants of \$9.2 million in 2013, \$10.2 million in 2012 and \$7.9 million during 2011, which are included in “Other operation and maintenance” expense, and made expenditures to handle waste ash of \$3.2 million in 2013, \$7.9 million in 2012 and \$8.7 million in 2011, which are included in “Fuel used in electric generation.” In addition, included within “Other operation and maintenance” expense is an annual amortization of \$1.4 million in each of 2013, 2012 and 2011 related to SCE&G's recovery of MGP remediation costs as approved by the SCPSC. It is not possible to estimate all future costs related to environmental matters, but forecasts for capitalized environmental expenditures for Consolidated SCE&G are \$9.5 million for 2014 and \$82.5 million for the four-year period 2015-2018. These expenditures are included in Consolidated SCE&G Estimated Capital Expenditures table, are discussed in Liquidity and Capital Resources, and include known costs related to the matters discussed below.

At the state level, no significant environmental legislation that would affect Consolidated SCE&G’s operations advanced during 2013. Consolidated SCE&G cannot predict whether such legislation will be introduced or enacted in 2014, or if new regulations or changes to existing regulations at the state level will be implemented in the coming year. Several regulatory initiatives at the federal level did advance in 2013 and more are expected to advance in 2014 as described below.

Air Quality

With the pervasive emergence of concern over the issue of global climate change as a significant influence upon the economy, Consolidated SCE&G is subject to climate-related financial risks, including those involving regulatory requirements responsive to GHG emissions, as well as those involving other potential physical impacts. Other business and financial risks arising from such climate change could also materialize. Consolidated SCE&G cannot predict all of the climate-related regulatory and physical risks nor the related consequences which might impact Consolidated SCE&G, and the following discussion should not be considered all-inclusive.

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. Consolidated SCE&G also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed herein.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed Consolidated SCE&G to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. Consolidated SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and Consolidated SCE&G's evaluation of the rule is ongoing. SCE&G's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in Consolidated SCE&G's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The EPA is conducting an enforcement initiative against the utilities industry related to the NSR provisions and the NSPS of the CAA. As part of the initiative, many utilities have received requests for information under Section 114 of the CAA. In addition, the DOJ, on behalf of the EPA, has taken civil enforcement action against several utilities. The primary basis for these actions is the assertion by the EPA that maintenance activities undertaken by the utilities at their coal-fired power plants constituted “major modifications” which required the installation of costly BACT. Some of the utilities subject to the actions have reached settlement. Though Consolidated SCE&G cannot predict what action, if any, the EPA will initiate against it, any costs incurred are expected to be recoverable through rates.

Physical effects associated with climate changes could include the impact of possible changes in weather patterns, such as storm frequency and intensity, and the resultant potential damage to Consolidated SCE&G’s electric system, as well as impacts on employees and customers and on its supply chain and many others. Much of the service territory of SCE&G is subject to the damaging effects of Atlantic and Gulf coast hurricanes and also to the damaging impact of winter ice storms. To help mitigate the financial risks arising from these potential occurrences, SCE&G maintains insurance on certain properties. In addition, SCE&G has collected funds from customers for its storm damage reserve (see Note 2 to the consolidated financial statements). As part of its ongoing operations, SCE&G maintains emergency response and storm preparation plans and teams who receive ongoing training and related simulations in advance of such storms, all in order to allow Consolidated SCE&G to protect its assets and to return its systems to normal reliable operation in a timely fashion following any such event.

Water Quality

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. Consolidated SCE&G is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of SCE&G and GENCO. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

Hazardous and Solid Wastes

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While Consolidated SCE&G cannot predict how extensive the regulations will be, Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

The final CCR rule may require the closure of ash ponds. SCE&G has three generating facilities that have employed ash storage ponds, and all of these ponds have either been closed after all ash was removed or are part of an ash pond closure project that includes complete removal of the ash prior to closure. The electric generating facilities which continue to be coal-fired have dry ash handling, and the ash ponds undergoing closure have a detailed dam safety inspection conducted at least quarterly.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2012, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017 and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the state of South Carolina has a similar law. Consolidated SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean up. In addition, regulators from the EPA and other federal or state agencies periodically notify Consolidated SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized with recovery provided through rates. Consolidated SCE&G has assessed the following matters:

Electric Operations

SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. At December 31, 2013, such regulatory assets totaled approximately $1.2 million. Other environmental costs are recorded to expense as incurred.

Gas Distribution

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC. SCE&G anticipates that major remediation activities at these sites will continue until 2017 and will cost an additional $21.2 million. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

REGULATORY MATTERS

SCE&G, GENCO and Fuel Company are subject to the regulatory jurisdiction of the following entities for the matters noted.

Company	Regulatory Jurisdiction/Matters
SCE&G, GENCO and Fuel Company	The CFTC to the extent they transact swaps as defined in Dodd-Frank.
SCE&G	The SEC as to the issuance of certain securities and other matters; the SCPSC as to retail electric and gas rates, service, accounting, issuance of securities (other than short-term borrowings) and other matters; the FERC as to issuance of short-term borrowings, guarantees of short-term indebtedness, certain acquisitions and other matters; the PHMSA as to integrity management requirements for gas distribution pipeline systems; and the NRC with respect to the ownership, construction, operation and decommissioning of its currently operated and planned nuclear generating facilities. NRC jurisdiction encompasses broad supervisory and regulatory powers over the construction and operation of nuclear reactors, including matters of health and safety, antitrust considerations and environmental impact. In addition, the Federal Emergency Management Agency reviews, in conjunction with the NRC, certain aspects of emergency planning relating to the operation of nuclear plants.
SCE&G and GENCO	The FERC and DOE, under the Federal Power Act, as to the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale for resale, the licensing of hydroelectric projects and certain other matters, including accounting.
GENCO	The SCPSC as to the issuance of securities (other than short-term borrowings) and the FERC as to the issuance of short-term borrowings, accounting, certain acquisitions and other matters.
Fuel Company	The SEC as to the issuance of certain securities.

Material retail rate proceedings are described in Note 2 to the consolidated financial statements. In addition, the RSA allows natural gas distribution companies in South Carolina to request annual adjustments to rates to reflect changes in revenues and expenses and changes in investment. Such annual adjustments are subject to certain qualifying criteria and review by the SCPSC.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Following are descriptions of Consolidated SCE&G's accounting policies and estimates which are most critical in terms of reporting financial condition or results of operations.

Utility Regulation

Consolidated SCE&G's regulated operations record certain assets and liabilities that defer the recognition of expenses and revenues to future periods in accordance with accounting guidance for rate-regulated utilities. In the future, in the event of deregulation or other changes in the regulatory environment, Consolidated SCE&G may no longer meet the criteria of accounting for rate-regulated utilities, and could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on the results of operations, liquidity or financial position of Consolidated SCE&G's Electric Operations and Gas Distribution segments in the period the write-off would be recorded. See Note 2 to the consolidated financial statements for a description of Consolidated SCE&G's regulatory assets and liabilities, including those associated with Consolidated SCE&G's environmental program.

Consolidated SCE&G's generation assets would be exposed to considerable financial risks in a deregulated electric market. If market prices for electric generation do not produce adequate revenue streams and the enabling legislation or regulatory actions do not provide for recovery of the resulting stranded costs, Consolidated SCE&G could be required to write down its investment in those assets. Consolidated SCE&G cannot predict whether any write-downs would be necessary and, if they were, the extent to which they would affect Consolidated SCE&G's results of operations in the period in which they would be recorded. As of December 31, 2013, Consolidated SCE&G's net investments in fossil/hydro and nuclear generation assets were $2.4 billion and $2.9 billion, respectively.

Revenue Recognition and Unbilled Revenues

Revenues related to the sale of energy are recorded when service is rendered or when energy is delivered to customers. Because customers are billed on cycles which vary based on the timing of the actual reading of their electric and gas meters, SCE&G records estimates for unbilled revenues at the end of each reporting period. Such unbilled revenue amounts reflect estimates of the amount of energy delivered to customers for which they have not yet been billed. Such unbilled revenues reflect consideration of estimated usage by customer class, the effects of different rate schedules and, where applicable, the impact of weather normalization provisions of rate structures. The accrual of unbilled revenues in this manner properly matches revenues and related costs. As of December 31, 2013 and 2012, accounts receivable included unbilled revenues of $111.9 million and $129.0 million, respectively, compared to total revenues of $2.8 billion for each of such years.

Nuclear Decommissioning

Accounting for decommissioning costs for nuclear power plants involves significant estimates related to costs to be incurred many years into the future. Among the factors that could change SCE&G's accounting estimates related to decommissioning costs are changes in technology, changes in regulatory and environmental remediation requirements, and changes in financial assumptions such as discount rates and timing of cash flows. Changes in any of these estimates could significantly impact SCE&G's financial position and cash flows (although changes in such estimates should be earnings-neutral, because these costs are expected to be collected from ratepayers).

Based on a decommissioning cost study, SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including both the cost of decommissioning plant components that are and are not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that upon closure the site would be maintained for 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates are invested in insurance policies on the lives of certain Company personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures on an after-tax basis.

Asset Retirement Obligations

Consolidated SCE&G accrues for the legal obligation associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation in accordance with applicable accounting guidance. The obligations are recognized at present value in the period in which they are incurred and associated asset retirement costs are capitalized as a part of the carrying amount of the related long-lived assets. Because such obligations relate primarily to Consolidated SCE&G's utility operations, their recognition has no significant impact on results of operations. As of December 31, 2013, Consolidated SCE&G has recorded AROs of $191 million for nuclear plant decommissioning (as discussed above) and AROs of $356 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded in accordance with the relevant accounting guidance are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments may be made many years in the future. Changes in these estimates will be recorded over time; however, these changes in estimates are not expected to materially impact results of operations so long as the regulatory framework for utilities remains in place.

Accounting for Pensions and Other Postretirement Benefits

SCE&G participates in SCANA’s noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA recognizes the funded status of its defined benefit pension plan as an asset or liability and changes in funded status as a component of net periodic benefit cost or other comprehensive income, net of tax, or as a regulatory asset as required by accounting guidance. SCANA’s plan is adequately funded under current regulations. Accounting guidance requires the use of several assumptions, the selection of which has an impact on the resulting pension cost recorded. Among the more sensitive assumptions are those surrounding discount rates and expected returns on assets. SCANA's net pension cost of $31.7 million ($26.0 million attributable to SCE&G) recorded in 2013 reflects the use of a 4.10% discount rate prior to re-measurement on September 1, 2013 and a 5.07% discount rate after the re-measurement, derived using a cash flow matching technique, and an assumed 8.00% long-term rate of return on plan assets. The re-measurement occurred in connection with a plan amendment and related curtailment, which is further described below. SCANA believes that these assumptions were, and that the resulting pension cost amount was, reasonable. For purposes of comparison, a 25 basis point reduction in the discount rate in 2013 would have increased SCANA's pension cost by $1.2 million. Further, had the assumed long-term rate of return on assets been 7.75%, SCANA's pension cost for 2013 would have increased by $1.9 million.

The following information with respect to pension assets (and returns thereon) should also be noted.

SCANA determines the fair value of a large majority of its pension assets utilizing market quotes or derives them from modeling techniques that incorporate market data. Less than 10% of assets are valued using less transparent Level 3 methods.

In developing the expected long-term rate of return assumptions, SCANA evaluates historical performance, targeted allocation amounts and expected payment terms. As of the beginning of 2013, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 7.5%, 6.3%, 8.8% and 9.7%, respectively. The 2013 expected long-term rate of return of 8.00% was based on a target asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. SCANA regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. As of the beginning of 2014, the plan's historical 10, 15, 20 and 25 year cumulative performance showed actual returns of 6.4%, 6.0%, 8.3% and 9.3%, respectively. For 2014, the expected rate of return is 8.00%.

As of December 31, 2013, 2012, and 2011, approximately $5.5 million, $14.9 million and $9.0 million, respectively, of pension expense was deferred pursuant to regulatory orders. As part of a December 2012 SCPSC rate order, cumulative previously deferred pension costs related to electric operations of approximately $63 million is being amortized over approximately 30 years, and starting in January 2013 current pension expense for electric operations is being recovered through a pension cost rider. Similarly, in connection with the October 2013 RSA order, previously deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates.

In the third quarter of 2013, the pension plan was amended such that pension benefits will no longer be offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. As a result, SCANA recorded a curtailment charge due to the accelerated amortization of prior service cost. Approximately $5.3 million of the curtailment charge was applicable to regulated operations and was deferred within regulatory assets. SCE&G is recovering such deferred amounts through existing regulatory orders.

The closure of the plan to entrants after December 31, 2013 and the cessation of benefit accruals in 2023 are expected to further lessen the significance of pension costs and the criticality of the related estimates to SCE&G's financial statements. Further, the pension trust is adequately funded under current regulations, and management does not anticipate the need to make significant pension contributions for the foreseeable future.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. SCANA accounts for the cost of postretirement medical and life insurance benefit plans in a similar manner to that used for its defined benefit pension plan. This plan is unfunded, so no assumptions related to rate of return on assets impact the net expense recorded; however, the selection of discount rates can significantly impact the actuarial determination of net expense. SCANA used a discount rate of 4.19%, derived using a cash flow matching technique, and recorded a net cost to SCE&G of $16.5 million for 2013. Had the selected discount rate been 3.94% (25 basis points lower than the discount rate referenced above), the expense for 2013 would have been $0.5 million higher. Because the plan provisions include “caps” on company per capita costs, and because employees hired after December 31, 2010 are responsible for the full cost of retiree medical benefits elected by them, healthcare cost inflation rate assumptions do not materially impact the net expense recorded.

NEW NUCLEAR CONSTRUCTION MATTERS

SCE&G is constructing two 1,250 MW (1,117 MW, net) nuclear generation units at the site of Summer Station. SCE&G will jointly own the New Units with Santee Cooper, and SCE&G will be responsible for the cost of and receive the output from the New Units in proportion to its share of ownership, with Santee Cooper responsible for and receiving the remaining share. SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement, SCE&G will acquire a one percent ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional two percent ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final two percent no later than the second anniversary of such commercial operation date. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete.

It is expected that Unit 2 will be placed in service in the fourth quarter of 2017 or the first quarter of 2018, with Unit 3's in-service date approximately 12 months later. SCE&G's share of the estimated cash outlays (future value, excluding AFC) for its current 55% ownership share totals approximately $5.4 billion for plant and related transmission infrastructure costs, which costs are projected based on historical one-year and five-year escalation rates as required by the SCPSC. In addition, under the terms of the agreement previously described, SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in revised rates filings under the BLRA.

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution of these specific claims is discussed in Note 2 to the consolidated financial statements. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide for detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that this revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification. Under current provisions of the Internal Revenue Code and based on SCE&G's current 55% ownership and other assumptions regarding volumes of electricity to be generated by the New Units, the aggregate production tax credits for which SCE&G qualifies could exceed $1.3 billion over the eight year period following each of the New Units' in-service dates. In January 2014, SCE&G amended its application to include the additional 5% interest in the New Units that it expects to acquire. Additional production tax credits related to the 5% interest could total as much as $125 million.

OTHER MATTERS

Financial Regulatory Reform

Dodd-Frank provides for substantial additional regulation of over-the-counter and security-based derivative instruments, among other things, and requires numerous rule-makings by the CFTC and the SEC to implement. Consolidated SCE&G has determined that it meets the end-user exception in Dodd-Frank, with the lowest level of required regulatory reporting burden imposed by this law. Consolidated SCE&G is currently complying with these enacted regulations and intends to comply with regulations enacted in the future, but cannot predict when the final regulations will be issued or what requirements they will impose.

Off-Balance Sheet Transactions

Consolidated SCE&G does not hold significant investments in unconsolidated special purpose entities. Consolidated SCE&G does not engage in off-balance sheet financing or similar transactions, although it is party to incidental operating leases in the normal course of business, generally for office space, furniture, vehicles, equipment and rail cars, none of which are considered significant.

Claims and Litigation

For a description of claims and litigation see Note 10 to the consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

All financial instruments held by Consolidated SCE&G described below are held for purposes other than trading.

The tables below provide information about long-term debt issued by Consolidated SCE&G which is sensitive to changes in interest rates. For debt obligations, the tables present principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the figures shown reflect notional amounts, weighted average rates and related maturities. Fair values for debt represent quoted market prices. Interest rate swap agreements are valued using discounted cash flow models with independently sourced data.

	Expected Maturity Date							
December 31, 2013 Millions of dollars	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	45.2	9.2	108.6	8.2	717.9	3,086.5	3,975.6	4,356.6
Average Interest Rate (%)	4.84	4.73	1.11	4.96	5.95	6.62	6.32	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	64.9
Average Variable Interest Rate (%)	—	—	—	—	—	0.11	0.11	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	600.0	650.0	—	—	—	71.4	1,321.4	30.6
Average Pay Interest Rate (%)	3.96	4.16	—	—	—	3.29	4.02	—
Average Receive Interest Rate (%)	0.25	0.25	—	—	—	0.06	0.24	—

	Expected Maturity Date							
December 31, 2012 Millions of dollars	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value
Long-Term Debt:								
Fixed Rate ($)	159.5	45.1	8.6	8.1	7.7	3,405.9	3,634.9	4,458.0
Average Interest Rate (%)	6.98	4.84	4.85	5.01	5.12	5.60	5.65	—
Variable Rate ($)	—	—	—	—	—	67.8	67.8	65.8
Average Variable Interest Rate (%)	—	—	—	—	—	0.17	0.17	—
Interest Rate Swaps:								
Pay Fixed/Receive Variable ($)	600.0	300.0	—	—	—	71.4	971.4	(2.5)
Average Pay Interest Rate (%)	3.01	2.48	—	—	—	3.29	2.87	—
Average Receive Interest Rate (%)	0.31	0.31	—	—	—	0.13	0.29	—

While a decrease in interest rates would increase the fair value of debt, it is unlikely that events which would result in a realized loss will occur.

The above tables exclude long-term debt of $3 million at December 31, 2013 and $9 million at December 31, 2012, which amounts do not have stated interest rates associated with them.

For further discussion of Consolidated SCE&G's long-term debt and interest rate derivatives, see Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources and Notes 4 and 6 to the consolidated financial statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholder of
South Carolina Electric & Gas Company
Cayce, South Carolina

We have audited the accompanying consolidated balance sheets of South Carolina Electric & Gas Company and affiliates (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows, and changes in equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in Part IV at Item 15. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED BALANCE SHEETS

December 31, (Millions of dollars)	2013	2012
Assets		
Utility Plant In Service	$10,378	$10,096
Accumulated Depreciation and Amortization	(3,499)	(3,322)
Construction Work in Progress	2,682	2,073
Plant to be Retired, Net	177	362
Nuclear Fuel, Net of Accumulated Amortization	310	166
Utility Plant, Net ($720 and $640 related to VIEs)	10,048	9,375
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	69	57
Assets held in trust, net-nuclear decommissioning	101	94
Other investments	3	3
Nonutility Property and Investments, Net	173	154
Current Assets:		
Cash and cash equivalents	92	51
Receivables, net of allowance for uncollectible accounts of $3 and $3	486	483
Receivables-affiliated companies	19	2
Inventories:		
Fuel	131	203
Materials and supplies	120	126
Emission allowances	1	1
Prepayments and other	80	143
Total Current Assets ($147 and $206 related to VIEs)	929	1,009
Deferred Debits and Other Assets:		
Pension asset	96	—
Regulatory assets	1,303	1,377
Other	151	189
Total Deferred Debits and Other Assets ($35 and $54 related to VIEs)	1,550	1,566
Total	$12,700	$12,104

See Notes to Consolidated Financial Statements.

December 31, (Millions of dollars)	2013	2012
Capitalization and Liabilities		
Common equity	$4,372	$3,929
Noncontrolling interest	117	114
Total Equity	4,489	4,043
Long-Term Debt, net	4,007	3,557
Total Capitalization	8,496	7,600
Current Liabilities:		
Short-term borrowings	251	449
Current portion of long-term debt	48	165
Accounts payable	241	281
Affiliated payables	117	124
Customer deposits and customer prepayments	56	51
Taxes accrued	223	151
Interest accrued	64	63
Dividends declared	62	46
Derivative financial instruments	1	66
Other	71	50
Total Current Liabilities	1,134	1,446
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,509	1,479
Deferred investment tax credits	32	36
Asset retirement obligations	547	535
Postretirement benefits	173	254
Regulatory liabilities	732	665
Other	77	89
Total Deferred Credits and Other Liabilities	3,070	3,058
Commitments and Contingencies (Note 10)	—	—
Total	$12,700	$12,104

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Operating Revenues:			
Electric	$2,431	$2,453	$2,432
Gas	414	356	387
Total Operating Revenues	2,845	2,809	2,819
Operating Expenses:			
Fuel used in electric generation	751	844	922
Purchased power	43	28	19
Gas purchased for resale	244	197	240
Other operation and maintenance	557	542	515
Depreciation and amortization	313	293	286
Other taxes	200	188	183
Total Operating Expenses	2,108	2,092	2,165
Operating Income	737	717	654
Other Income (Expense):			
Other income	53	—	5
Other expenses	(18)	(18)	(12)
Interest charges, net of allowance for borrowed funds used during construction of $13, $11 and $7	(217)	(211)	(204)
Allowance for equity funds used during construction	25	21	13
Total Other Expense	(157)	(208)	(198)
Income Before Income Tax Expense	580	509	456
Income Tax Expense	189	157	140
Net Income	391	352	316
Less Net Income Attributable to Noncontrolling Interest	11	11	10
Earnings Available to Common Shareholder	$380	$341	$306

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31, (Millions of dollars)	2013	2012	2011
Net Income	$391	$352	$316
Other Comprehensive Income (Loss), net of tax:			
Deferred costs of employee benefit plans, net of tax $-, $- and $-	1	(1)	(1)
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax $-, $- and $-	—	—	—
Other Comprehensive Income (Loss)	1	(1)	(1)
Total Comprehensive Income	392	351	315
Less comprehensive income attributable to noncontrolling interest	(11)	(11)	(10)
Comprehensive income available to common shareholder	$381	$340	$305

See Notes to Consolidated Financial Statement

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, (Millions of dollars)	2013	2012	2011
Cash Flows From Operating Activities:			
Net income	$391	$352	$316
Adjustments to reconcile net income to net cash provided from operating activities:			
Losses from equity method investments	3	4	2
Deferred income taxes, net	29	116	138
Depreciation and amortization	315	294	288
Amortization of nuclear fuel	57	44	40
Allowance for equity funds used during construction	(25)	(21)	(13)
Carrying cost recovery	(3)	—	—
Changes in certain assets and liabilities:			
Receivables	(36)	35	(31)
Inventories	35	(60)	(25)
Prepayments	(17)	(64)	82
Regulatory assets	83	(158)	(165)
Other regulatory liabilities	54	64	(12)
Accounts payable	5	27	(48)
Taxes accrued	72	1	13
Interest accrued	1	9	4
Pension and other postretirement benefits	(186)	69	70
Other assets	52	(84)	27
Other liabilities	22	46	(31)
Net Cash Provided From Operating Activities	852	674	655
Cash Flows From Investing Activities:			
Property additions and construction expenditures	(1,003)	(978)	(786)
Proceeds from investments and sales of assets (including derivative collateral posted)	144	275	11
Purchase of investments (including derivative collateral posted)	(116)	(268)	(57)
Payments upon interest rate derivative contract settlement	(49)	—	(31)
Proceeds from interest rate derivative contract settlement	163	14	—
Net Cash Used For Investing Activities	(861)	(957)	(863)
Cash Flows From Financing Activities:			
Proceeds from issuance of long-term debt	451	513	379
Contribution from parent	311	128	107
Repayment of long-term debt	(251)	(49)	(206)
Dividends	(241)	(202)	(205)
Short-term borrowings-affiliate, net	(22)	(9)	(13)
Short-term borrowings, net	(198)	(63)	131
Net Cash Provided From Financing Activities	50	318	193
Net Increase (Decrease) in Cash and Cash Equivalents	41	35	(15)
Cash and Cash Equivalents, January 1	51	16	31
Cash and Cash Equivalents, December 31	$92	$51	$16
Supplemental Cash Flow Information:			
Cash paid for—Interest (net of capitalized interest of $13, $11 and $7)	$200	$186	$181
—Income taxes	92	105	—

Noncash Investing and Financing Activities:			
Accrued construction expenditures	100	116	75
Capital lease	4	8	6
Nuclear fuel purchase	98	—	—

See Notes to Consolidated Financial Statements.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Millions	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Equity
Balance at January 1, 2011	40	$1,934	$1,505	$ (2)	$ 104	$3,541
Earnings available for common shareholder			306		10	316
Deferred cost of employee benefit plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			306	(1)	10	315
Capital contributions from parent		107				107
Cash dividends declared			(184)		(6)	(190)
Balance at December 31, 2011	40	2,041	1,627	(3)	108	3,773
Earnings Available for Common Shareholder			341		11	352
Deferred Cost of Employee Benefit Plans, net of tax $-				(1)		(1)
Total Comprehensive Income (Loss)			341	(1)	11	351
Capital contributions from parent		126			2	128
Cash dividends declared			(202)		(7)	(209)
Balance at December 31, 2012	40	2,167	1,766	(4)	114	4,043
Earnings Available for Common Shareholder			380		11	391
Deferred Cost of Employee Benefit Plans, net of tax $-				1		1
Total Comprehensive Income			380	1	11	392
Capital contributions from parent		312			(1)	311
Cash dividends declared			(250)		(7)	(257)
Balance at December 31, 2013	40	$2,479	$1,896	$ (3)	$ 117	$4,489

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

SCE&G, a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA, a South Carolina corporation. Consolidated SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

SCE&G has determined that it has a controlling financial interest in GENCO and Fuel Company (which are considered to be VIEs), and accordingly, the accompanying consolidated financial statements include the accounts of SCE&G, GENCO and Fuel Company. The equity interests in GENCO and Fuel Company are held solely by SCANA, SCE&G's parent. Accordingly, GENCO's and Fuel Company's equity and results of operations are reflected as noncontrolling interest in Consolidated SCE&G's consolidated financial statements. Intercompany balances and transactions between SCE&G, Fuel Company and GENCO have been eliminated in consolidation.

GENCO owns a coal-fired electric generating station with a 605 megawatt net generating capacity (summer rating). GENCO's electricity is sold, pursuant to a FERC-approved tariff, solely to SCE&G under the terms of a power purchase agreement and related operating agreement. The effects of these transactions are eliminated in consolidation. Substantially all of GENCO's property (carrying value of approximately $476 million) serves as collateral for its long-term borrowings. Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. Consolidated SCE&G calculated AFC using average composite rates of 6.9% for 2013, 6.3% for 2012 and 4.6% for 2011. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

Consolidated SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.94% in 2013, 2.91% in 2012 and 2.90% in 2011.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the DOE under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of Summer Station Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses is included in the corresponding operating expenses on its income statement.

As of December 31,	2013				2012			
	Unit 1		New Units		Unit 1		New Units	
Percent owned	66.7%		55.0%		66.7%		55.0%	
Plant in service	$1.1	billion	—		$1.1	billion	—	
Accumulated depreciation	$566.9	million	—		$557.0	million	—	
Construction work in progress	$127.1	million	$2.3	billion	$113.6	million	$1.8	billion

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC. For a discussion of when the New Units are expected to be placed in service, and a description of SCE&G's agreement to acquire an additional 5% ownership in the New Units, see Note 10.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $75.6 million at December 31, 2013 and $92.9 million at December 31, 2012.

Plant to be Retired

As previously disclosed, in 2012 SCE&G identified a total of six coal-fired units that it intends to retire by 2018, subject to future developments in environmental regulations, among other matters. These units had an aggregate generating capacity (summer 2012) of 730 MW. As of December 31, 2013, three of these units had been retired and their net carrying value is recorded in regulatory assets (see Note 2). The net carrying value of the remaining units is identified as Plant to be Retired, Net in the consolidated financial statements. SCE&G plans to request recovery of and a return on the net carrying value of these remaining units in future rate proceedings in connection with their retirement, and expects that such deferred amounts will be recovered through rates. In the meantime, these units remain in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections are classified as a regulatory asset or regulatory liability on the balance sheet (see Note 2). Other planned major maintenance is expensed when incurred.

Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the years ended December 31, 2013 and 2012, SCE&G incurred $18.1 million and $11.1 million, respectively, for turbine maintenance.

Nuclear refueling outages are scheduled 18 months apart. SCE&G accrued $1.2 million per month from January 2010 through December 2012 for its portion of the outages in the spring of 2011 and the fall of 2012. Total costs for the 2011 outage were $34.1 million, of which SCE&G was responsible for $22.7 million. Total costs for the 2012 outage were $32.3 million, of which SCE&G was responsible for $21.5 million. In connection with the SCPSC's December 2012 approval of SCE&G's retail electric rates (see Note 2), effective January 1, 2013, SCE&G began to accrue $1.4 million per month for its portion of the nuclear refueling outages that are scheduled to occur through the spring of 2020.

Nuclear Decommissioning

SCE&G's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $696.8 million, stated in 2012 dollars, pursuant an updated decommissioning cost study performed in 2012. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G's method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2013, 2012 and 2011) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

Consolidated SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements and treasury bills.

Accounts Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Inventory

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 used. Fuel inventory includes the average cost of coal, natural gas and fuel oil. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the SCPSC. Emission allowances are included in inventory at average cost. Emission allowances are expensed at weighted average cost as used and recovered through fuel cost recovery rates approved by the SCPSC.

Income Taxes

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA. Under a joint consolidated income tax allocation agreement, each SCANA subsidiary's current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to tax paying affiliates, including Consolidated SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense or revenues would be recognized by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (see Note 2) and are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

Consolidated SCE&G records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense as incurred.

Income Statement Presentation

In its consolidated statements of income, Consolidated SCE&G presents the revenues and expenses of its regulated activities (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

Consolidated SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not billed. Unbilled revenues totaled $111.9 million at December 31, 2013 and $129.0 million at December 31, 2012.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is adjusted through revenue and is deferred and included when determining the fuel cost component during subsequent hearings.

Customers subject to the PGA are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost of gas factor.

SCE&G’s gas rate schedules for residential, small commercial and small industrial customers include a WNA which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented an eWNA on a pilot basis for its electric customers; effective with the first billing cycle of 2014, the eWNA was discontinued as approved by the SCPSC. See Note 2.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Such taxes are not included in revenues or expenses in the statements of income.

2. RATE AND OTHER REGULATORY MATTERS

Electric - Cost of Fuel

SCE&G's retail electric rates include a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. In April 2012, the SCPSC approved SCE&G's request to decrease the total fuel cost component of its retail electric rates, and approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to recover an amount equal to its actual under-collected balance of base fuel and variable environmental costs as of April 30, 2012, or $80.6 million, over a twelve month period beginning with the first billing cycle of May 2012.

This April 2012 order was superseded, in part, by a December 2012 rate order in which the SCPSC authorized SCE&G to reduce the base fuel cost component of its retail electric rates and, in doing so, stated that SCE&G may not adjust its base fuel cost component prior to the last billing cycle of April 2014 except where necessary due to extraordinary unforeseen economic or financial conditions. In February 2013, in connection with its annual review of base rates for fuel costs, SCE&G requested authorization to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. Consistent with the December 2012 rate order, SCE&G did not request any adjustment to its base fuel cost component. In March 2013, SCE&G, ORS and the SCEUC entered into a settlement agreement accepting the proposed lower environmental fuel cost component effective with the first billing cycle of May 2013, and providing for the accrual of certain debt-related carrying costs on a portion of the under-collected balance of fuel costs. The SCPSC issued an order dated April 30, 2013, adopting and approving the settlement agreement and approving SCE&G's total fuel cost component. A public hearing for the annual review of base rates for fuel costs has been scheduled for April 3, 2014.

Pursuant to a November 2013 SCPSC accounting order, Consolidated SCE&G's electric revenue for 2013 was reduced for adjustments to the fuel cost component and related under-collected fuel balance of $41.6 million. Such adjustments are fully offset by the recognition within other income, also pursuant to that accounting order, of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability. See also Note 6.

Electric - Base Rates

In October 2013, SCE&G received an accounting order from the SCPSC directing it to remove from rate base deferred income tax assets arising from capital expenditures related to the New Units and to accrue carrying costs (recorded as a regulatory asset) on those amounts during periods in which they are not included in rate base. Such carrying costs are determined at SCE&G’s weighted average long-term borrowing rate, and during 2013, $2.9 million of such carrying costs were accrued within other income. SCE&G anticipates that when the New Units are placed in service and accelerated tax deprecation is recognized on them, these deferred income tax assets will decline. When these assets are fully offset by related deferred income tax liabilities, the carrying cost accruals will cease, and the regulatory asset will begin to be amortized.

In December 2012, the SCPSC approved a 4.23% overall increase in SCE&G's retail electric base rates, effective January 1, 2013, and authorized an allowed return on common equity of 10.25%. The SCPSC also approved a mid-period reduction to the cost of fuel component in rates (as discussed above), a reduction in the DSM Programs component rider to retail rates, and the recovery of and a return on the net carrying value of certain retired generating plant assets described below. In February 2013, the SCPSC denied the SCEUC's petition for rehearing and the denial was not appealed.

The eWNA was designed to mitigate the effects of abnormal weather on residential and commercial customers' bills and had been in use since August 2010. In connection with the December 2012 order, SCE&G agreed to perform a study of alternative structures for eWNA. On November 1, 2013, the ORS filed a report with the SCPSC recommending that the eWNA be terminated with the last billing cycle for December 2013. On November 26, 2013, SCE&G, ORS and certain other parties filed a joint petition with the SCPSC requesting, among other things, that the SCPSC discontinue the eWNA effective with bills rendered on or after the first billing cycle of January 2014. On December 20, 2013, the SCPSC granted the relief requested in the joint petition.

In connection with the above termination of the eWNA program effective December 31, 2013, electric revenues were reduced to reverse the prior accrual of an under-collected balance of $8.5 million. Pursuant to the SCPSC accounting order granting the above relief and terminating the eWNA, such revenue reduction was fully offset by the recognition within other income of $8.5 million of gains realized upon the settlement of certain interest rate derivatives which had been entered into in anticipation of the issuance of long-term debt, which gains had been deferred as a regulatory liability.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on a variety of factors, including customer energy demands, EPA regulations, reserve margins and fuel costs. SCE&G's 2012 IRP identified six coal-fired units that SCE&G has subsequently retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. One of these units was retired in 2012, and two others were retired in the fourth quarter of 2013. The net carrying value of these retired units is recorded in regulatory assets as unrecovered plant and is being amortized over the units' previously estimated remaining useful lives as approved by the SCPSC. The net carrying value of the remaining units is included in Plant to be Retired, Net in the consolidated financial statements. In connection with their retirement, SCE&G expects to be allowed a recovery of and a return on the net carrying value of these remaining units through rates. In the meantime, these units remain in rate base, and SCE&G continues to depreciate them using composite straight-line rates approved by the SCPSC.

In a July 2010 order, the SCPSC provided for a $48.7 million credit to SCE&G's customers over two years to be offset by accelerated recognition of previously deferred state income tax credits. These tax credits were fully amortized in 2012.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and lost net margin revenue associated with the DSM Programs, along with an incentive for investing in such programs. SCE&G submits annual filings regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. The SCPSC has approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated below:

Year	Effective	Amount
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million
2011	First billing cycle of June	$7.0 million

Other activity related to SCE&G's DSM Programs is as follows:

- In May 2013 the SCPSC ordered the deferral of one-half of the net lost revenues and provided for their recovery over a 12-month period beginning with the first billing cycle in May 2014.

- In November 2013 the SCPSC approved SCE&G's continued use of DSM programs for another six years, including approval of the rate rider mechanism and a revised portfolio of DSM programs.

- In January 2014 SCE&G submitted its annual DSM Programs filing to the SCPSC, which included, among other things, a request to (1) recover one-half of the balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2014 and to recover the remaining balance of allowable costs beginning with bills rendered on and after the first billing cycle of May 2015, (2) utilize approximately $17.8 million of the gains from the recent settlement of certain interest rate derivative instruments to offset a portion of the net lost revenues component of SCE&G's DSM Programs rider, and (3) apply $5 million of its storm damage reserve and a portion of the gains from the recent settlement of certain interest rate derivative instruments, currently estimated to be $5.5 million, to the remaining balance of deferred net lost revenue as of April 30, 2014, deferred within regulatory assets resulting from the May 2013 order previously described.

Electric - BLRA

In May 2011, the SCPSC approved an updated capital cost schedule sought by SCE&G that, among other matters, incorporated then-identifiable additional capital costs of $173.9 million (SCE&G's portion in 2007 dollars).

In November 2012, the SCPSC approved an updated construction schedule and additional updated capital costs of $278 million (SCE&G's portion in 2007 dollars). The November 2012 order approved additional identifiable capital costs of approximately $1 million (SCE&G's portion in 2007 dollars) related to new federal healthcare laws, information security measures, and certain minor design modifications; approximately $8 million (SCE&G's portion in 2007 dollars) related to transmission infrastructure; and approximately $132 million (SCE&G's portion in 2007 dollars) related to additional labor for the oversight of the New Units during construction and for preparing to operate the New Units, and facilities and information technology systems required to support the New Units and their personnel. In addition, the order approved revised substantial completion dates for the New Units based on the March 30, 2012 issuance of the COL and the amounts agreed upon by SCE&G and the Consortium in July 2012 to resolve claims for costs related to COL delays, design modifications of the shield building and certain pre-fabricated structural modules for the New Units and unanticipated rock conditions at the site. Thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its November 2012 order. On December 12, 2012, the SCPSC denied both petitions. In March 2013, both parties appealed the SCPSC's order to the South Carolina Supreme Court. SCE&G is unable to predict the outcome of these appeals. For further discussion of new nuclear construction matters, see Note 9.

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11.0%. The SCPSC has approved the following rate changes under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount	
2013	2.90%	$67.2	million
2012	2.30%	$52.1	million
2011	2.40%	$52.8	million

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the first billing cycle of November in the following years:

Year	Action			Amount	
2013	No change				
2012	2.10	%	Increase	$7.5	million
2011	2.10	%	Increase	$8.6	million

SCE&G's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the SCPSC. The annual reviews conducted for each of the 12-month periods ended July 31, 2013 and 2012 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during each review period were reasonable and prudent.

Regulatory Assets and Regulatory Liabilities

Consolidated SCE&G has significant cost-based, rate-regulated operations and recognizes in its financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, Consolidated SCE&G has recorded regulatory assets and regulatory liabilities, which are summarized in the following tables. Other than unrecovered plant, substantially all of our regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	2013	2012
Regulatory Assets:		
Accumulated deferred income taxes	$256	$248
Under-collections-electric fuel adjustment clause	18	66
Environmental remediation costs	37	39
AROs and related funding	350	304
Franchise agreements	31	36
Deferred employee benefit plan costs	215	405
Planned major maintenance	—	6
Deferred losses on interest rate derivatives	124	151
Deferred pollution control costs	37	38
Unrecovered Plant	145	20
DSM Programs	51	27
Other	39	37
Total Regulatory Assets	$1,303	$1,377

Regulatory Liabilities:		
Accumulated deferred income taxes	$19	$21
Asset removal costs	495	507
Storm damage reserve	27	27
Deferred gains on interest rate derivatives	181	110
Planned major maintenance	10	—
Total Regulatory Liabilities	$732	$665

Accumulated deferred income tax liabilities that arose from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections - electric fuel adjustment clause represent amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC which are expected to be recovered in retail electric rates over periods exceeding 12 months.

Environmental remediation costs represent costs associated with the assessment and clean-up of sites currently or formerly owned by SCE&G and are expected to be recovered over periods of up to approximately 26 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station and conditional AROs related to generation, transmission and distribution properties, including gas pipelines. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 90 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on a SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific SCPSC regulatory orders. In connection with the December 2012 rate order, approximately $63 million of deferred pension costs for electric operations are being recovered through utility rates over approximately 30 years. In connection with the October 2013 RSA order, approximately $14 million of deferred pension costs for gas operations are being recovered through utility rates over approximately 14 years. The remainder of the deferred benefit costs are expected to be recovered through utility rates, primarily over average service periods of participating employees, or up to approximately 12 years.

Planned major maintenance related to certain fossil-fueled turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collects $18.4 million annually for such equipment maintenance. Through December 31, 2012, nuclear refueling charges were accrued during each 18-month refueling outage cycle as a component of cost of service. In connection with the December 2012 rate order, effective January 1, 2013, SCE&G collects and accrues $16.8 million annually for nuclear-related refueling charges.

Deferred losses or gains on interest rate derivatives represent (i) the effective portions of changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges and (ii) the changes in fair value and payments received upon settlement of certain other interest rate derivatives not so designated. The amounts recorded with respect to (i) are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years. The amounts recorded with respect to (ii) are expected to be similarly amortized to interest expense except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the installation of scrubbers at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs are being recovered through utility rates over periods up to 30 years.

Unrecovered plant represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. Pursuant to SCPSC approval, SCE&G is amortizing these amounts through cost of service rates over the units' previous estimated remaining useful lives, or up to approximately 14 years. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represents deferred costs and certain unrecovered lost revenue associated with SCE&G’s Demand Side Management programs. Deferred costs are currently being recovered over 5 years through a SCPSC approved rider. Unrecovered lost revenue is to be recovered over periods not to exceed 24 months from date of deferral. See Rate Matters - Electric Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs and unrecovered lost revenue.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the non-legal obligation to remove assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year. Pursuant to specific regulatory orders, SCE&G has suspended storm damage reserve collection through rates indefinitely.

The SCPSC or the FERC has reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by the SCPSC or by the FERC. In recording such costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, Consolidated SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on Consolidated SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

The balance for accumulated other comprehensive income (loss), net of tax, was as follows:

Millions of Dollars	Deferred Employee Benefit Plans	
Accumulated Other Comprehensive Loss as of January 1, 2012	$(3	)
Other comprehensive loss	(1	)
Accumulated Other Comprehensive Loss as of December 31, 2012	(4	)
Other comprehensive income	1	
Accumulated Other Comprehensive Loss as of December 31, 2013	$(3	)

Authorized shares of SCE&G common stock were 50 million as of December 31, 2013 and 2012. Authorized shares of SCE&G preferred stock were 20 million, of which 1,000 shares, no par value, were held by SCANA as of December 31, 2013 and 2012.

SCE&G’s articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G’s bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

The Federal Power Act requires the appropriation of a portion of certain earnings from hydroelectric projects. At December 31, 2013 and 2012, approximately $63.1 million and $61.0 million of retained earnings, respectively, were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities at December 31 is as follows:

		2013			2012		
Dollars in millions	Maturity	Balance	Rate		Balance	Rate	
First Mortgage Bonds (secured)	2018 - 2042	$3,540	5.60	%	$3,290	5.66	%
GENCO Notes (secured)	2018 - 2024	233	5.89	%	240	5.87	%
Industrial and Pollution Control Bonds (a)	2014 - 2038	158	3.83	%	161	4.32	%
Nuclear Fuel Financing	2016	100	0.78	%	—	—	
Other	2014 - 2027	16	2.26	%	21	1.62	%
Total debt		4,047			3,712		
Current maturities of long-term debt		(48	)		(165	)	
Unamortized premium		8			10		
Total long-term debt, net		$4,007			$3,557		

(a) Includes variable rate debt of $67.8 million at December 31, 2013 (rate of 0.11%) and 2012 (rate of 0.17%), which are hedged by fixed swaps.

The annual amounts of long-term debt maturities for the years 2014 through 2018 are summarized as follows:

Year	Millions of dollars
2014	$48
2015	9
2016	109
2017	8
2018	718

In June 2013, SCE&G issued $400 million of 4.60% first mortgage bonds due June 15, 2043. Proceeds from this sale were used to pay at maturity $150 million of its 7.125% first mortgage bonds due June 15, 2013, to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures, and for general corporate purposes.

In March 2013, SCE&G entered into a contract for the purchase of nuclear fuel totaling $100 million and payable in 2016.

In January 2013, JEDA issued for the benefit of SCE&G $39.5 million of 4.0% tax-exempt industrial revenue bonds due February 1, 2028, and $14.7 million of 3.63% tax-exempt industrial revenue bonds due February 1, 2033. Proceeds from these sales were loaned by JEDA to SCE&G and, together with other available funds, were used to redeem prior to maturity $56.9 million of 5.2% industrial revenue bonds due November 1, 2027. The borrowings refinanced by these 2013 issuances are classified within Long-term Debt, Net in the consolidated balance sheet.

In July 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042, which constituted a reopening of the prior offering of $250 million of 4.35% first mortgage bonds issued in January 2012. Proceeds from these sales were used to repay short-term debt primarily incurred as a result of SCE&G's construction program, to finance capital expenditures and for general corporate purposes.

Substantially all of SCE&G’s and GENCO’s electric utility plant is pledged as collateral in connection with long-term debt.

SCE&G is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice (2.0) the annual interest requirements on all outstanding Bonds and Bonds to be outstanding (Bond Ratio). For the year ended December 31, 2013, the Bond Ratio was 5.28.

Lines of Credit and Short-Term Borrowings

At December 31, 2013 and 2012, SCE&G (including Fuel Company) had available the following committed LOC and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

Millions of dollars	2013		2012	
Lines of credit:				
Total committed long-term	$1,400		$1,400	
LOC advances	—		—	
Weighted average interest rate	—		—	
Outstanding commercial paper (270 or fewer days)	$251		$449	
Weighted average interest rate	0.27	%	0.42	%
Letters of credit supported by an LOC	$0.3		$0.3	
Available	$1,149		$951	

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.2 billion (of which $500 million relates to Fuel Company). In addition, SCE&G is party to a three-year credit agreement in the amount of $200 million. In October 2013, the term of each of these credit agreements was extended by one year, such that the five-year agreements will expire in October 2018, and the three-year agreement expires in October 2016. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10.7% of the aggregate $1,400 million credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC each provide 8.9% and Branch Banking and Trust Company, Union Bank, N.A. and U.S. Bank National Association each provide 6.3%. Two other banks provide the remaining support. Consolidated SCE&G pays fees to the banks as compensation for maintaining the committed lines of credit. Such fees were not material in any period presented.
Consolidated SCE&G is obligated with respect to an aggregate of $67.8 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. These letters of credit expire, subject to renewal, in the fourth quarter of 2014.

Consolidated SCE&G pays fees to the banks as compensation for maintaining committed lines of credit. Such fees were not material in any period presented.

Consolidated SCE&G participates in a utility money pool with SCANA and certain other subsidiaries of SCANA. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions was not significant for any period presented. At December 31, 2013 and 2012, Consolidated SCE&G had outstanding money pool borrowings due to an affiliate of $27.3 million and $49.4 million, respectively, which are included within affiliated payables on the consolidated balance sheet.

5. INCOME TAXES

Components of income tax expense for 2013, 2012, and 2011 are as follows:

Millions of dollars	2013	2012	2011
Current taxes:			
Federal	$146	$91	$52
State	13	8	12
Total current taxes	159	99	64
Deferred taxes, net:			
Federal	25	62	98
State	9	12	6
Total deferred taxes	34	74	104
Investment tax credits:			
Amortization of amounts deferred—state	(1)	(13)	(25)
Amortization of amounts deferred—federal	(3)	(3)	(3)
Total investment tax credits	(4)	(16)	(28)
Total income tax expense	$189	$157	$140

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2013	2012	2011
Net income	$380	$341	$306
Income tax expense	189	157	140
Noncontrolling interest	11	11	10
Total pre-tax income	$580	$509	$456
Income taxes on above at statutory federal income tax rate	$203	$178	$159
Increases (decreases) attributed to:			
State income taxes (less federal income tax effect)	18	17	12
State investment tax credits (less federal income tax effect)	(5)	(13)	(16)
Allowance for equity funds used during construction	(9)	(7)	(5)
Amortization of federal investment tax credits	(3)	(3)	(3)
Section 45 tax credits	(5)	(5)	(2)
Domestic production activities deduction	(11)	(9)	(6)
Other differences, net	1	(1)	1
Total income tax expense	$189	$157	$140

The tax effects of significant temporary differences comprising Consolidated SCE&G’s net deferred tax liability at December 31, 2013 and 2012 are as follows:

Millions of dollars	2013	2012
Deferred tax assets:		
Nondeductible accruals	$17	$73
Asset retirement obligation, including nuclear decommissioning	209	204
Unamortized investment tax credits	19	21
Unbilled revenue	—	14
Regulatory liability, net gain on interest rate derivative contracts settlement	27	—
Other	11	13
Total deferred tax assets	283	325
Deferred tax liabilities:		
Property, plant and equipment	$1,494	$1,461
Regulatory asset-asset retirement obligation	114	107
Deferred employee benefit plan costs	54	127
Deferred fuel costs	26	49
Regulatory asset, unrecovered plant	55	7
Other	62	53
Total deferred tax liabilities	1,805	1,804
Net deferred tax liability	$1,522	$1,479

Consolidated SCE&G is included in the consolidated federal income tax return of SCANA and files various applicable state and local income tax returns. The IRS has completed examinations of SCANA’s federal returns through 2004, and SCANA’s federal returns through 2007 are closed for additional assessment. With few exceptions, Consolidated SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2009.

Changes to Unrecognized Tax Benefits

Millions of dollars	2013	2012	2011
Unrecognized tax benefits, January 1	—	$38	$36
Gross increases-uncertain tax positions in prior period	—	—	5
Gross decreases-uncertain tax positions in prior period	—	(38)	(8)
Gross increases-current period uncertain tax positions	$3	—	5
Settlements	—	—	—
Lapse of statute of limitations	—	—	—
Unrecognized tax benefits, December 31	$3	$—	$38

In connection with the change in method of tax accounting for certain repair costs in prior years, the Company had previously recorded an unrecognized tax benefit. During the first quarter of 2012, the publication of new administrative guidance from the IRS allowed Consolidated SCE&G to recognize this benefit. Since this change was primarily a temporary difference, the recognition of this benefit did not have a significant effect on the Consolidated SCE&G's effective tax rate.

During 2013, Consolidated SCE&G amended certain of its tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, Consolidated SCE&G recorded an unrecognized tax benefit of $3 million. If recognized, this tax benefit would affect Consolidated SCE&G’s effective tax rate. It is reasonably possible that this tax benefit will increase by an additional $5 million within the next 12 months. No other material changes in the status of the Consolidated SCE&G’s tax positions have occurred through December 31, 2013.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. In connection with the resolution of the uncertainty and recognition of the tax benefit in 2012, during 2012 Consolidated SCE&G reversed $2 million of interest expense which had been accrued during 2011. Consolidated SCE&G has not recorded interest expense or penalties associated with the 2013 uncertain tax position.

6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in its statements of financial position and measures those instruments at fair value. Consolidated SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by Consolidated SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including Consolidated SCE&G. The Risk Management Committee, which is comprised of certain officers, including Consolidated SCE&G's Risk Management Officer and senior officers, apprises the Audit Committee of the Board of Directors with regard to the management of risk and brings to the Audit Committee's attention significant areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Interest Rate Swaps

Consolidated SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense.

In anticipation of the issuance of debt, Consolidated SCE&G may use treasury rate lock or forward starting swap agreements. Pursuant to regulatory orders issued in 2013, interest rate derivatives entered into by SCE&G after October 2013 are no longer designated as cash flow hedges, and fair value changes and settlement amounts are recorded as regulatory assets and liabilities. Upon settlement, losses on swaps will be amortized over the lives of related debt issuances, and gains may be applied to under-collected fuel, be amortized to interest expense or applied as otherwise directed by the SCPSC. As discussed in Note 2, in these orders, the SCPSC directed SCE&G to recognize $41.6 million and $8.5 million of realized gains (which had been deferred in regulatory liabilities) within other income, fully offsetting revenue reductions related to under-collected fuel balances and under-collected amounts arising under the eWNA program which was terminated at the end of 2013. Prior to this regulatory authorization, such interest rate derivatives were designated as cash flow hedges, and only the effective portions of changes in fair value and payments made or received upon termination of such agreements were recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions were recognized in income.

Cash payments made or received upon settlement of these financial instruments are classified as investing activities for cash flow statement purposes.

Quantitative Disclosures Related to Derivatives

Consolidated SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $36.4 million and $971.4 million at December 31, 2013 and 2012, respectively. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.3 billion and $0.0 million at December 31, 2013 and 2012, respectively.

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The fair value of interest rate derivatives was reflected in the consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
Millions of dollars	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Other current liabilities	$1
Total				$1
Derivatives not designated as hedging instruments				
Interest rate contracts	Prepayments and other	$13	Other current liabilities	$1
	Other deferred debits and other assets	19		
Total		$32		$1
As of December 31, 2012				
Derivatives designated as hedging instruments				
Interest rate contracts	Prepayments and other	$42	Other current liabilities	$66
	Other deferred debits and other assets	31	Other deferred credits and other liabilities	9
Total		$73		$75

The effect of derivative instruments on the consolidated statement of income is as follows:

Derivatives in Cash Flow Hedging Relationships	Gain or (Loss) Deferred in Regulatory Accounts	Loss Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	(Effective Portion)	Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$106	Interest expense	$(3)
Year Ended December 31, 2012			
Interest rate contracts	$84	Interest expense	$(3)
Year Ended December 31, 2011			
Interest rate contracts	$(76)	Interest expense	$(3)

Hedge Ineffectiveness

Other losses recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in 2013 and 2012 and were $(1.1) million, net of tax, in 2011.

Derivatives Not Designated as Hedging Instruments	Loss Recognized in Income	Year Ended December 31,		
Millions of dollars	Location	2013	2012	2011
Commodity contracts	Gas purchased for resale	—	$(1)	$(2)

Millions of dollars	Gain Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income Location	Amount
Year Ended December 31, 2013			
Interest rate contracts	$39	Other income	$50
Year Ended December 31, 2012			
Interest rate contracts	—		—
Year Ended December 31, 2011			
Interest rate contracts	—		—

The gains reclassified to other income of $50 million offset revenue reductions as previously described herein and in Note 2.

Credit Risk Considerations

Consolidated SCE&G limits credit risk in its derivatives activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. In this regard, Consolidated SCE&G uses credit ratings provided by credit rating agencies and current market-based qualitative and quantitative data, as well as financial statements, to assess the financial health of counterparties on an ongoing basis. Consolidated SCE&G uses standardized master agreements which generally include collateral requirements. These master agreements permit the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with Consolidated SCE&G's credit policies and due diligence. In addition, collateral agreements allow for the termination and liquidation of all positions in the event of a failure or inability to post collateral.

Certain of Consolidated SCE&G’s derivative instruments contain contingent provisions that require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit rating downgrades. As of December 31, 2013 and 2012, Consolidated SCE&G had posted $1.5 million and $35.2 million, respectively, of collateral related to derivatives with contingent provisions that were in a net liability position. Collateral related to the positions expected to close in the next 12 months are recorded in Prepayments and other on the consolidated balance sheets. Collateral related to the noncurrent positions are recorded in Other within Deferred Debits and Other Assets on the consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and 2012, Consolidated SCE&G would have been required to post an additional $0.0 million and $22.7 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2013 and 2012, are $1.0 million and $57.9 million, respectively.

In addition, as of December 31, 2013 and December 31, 2012, Consolidated SCE&G has collected no cash collateral related to interest rate derivatives with contingent provisions that are in a net asset position. If all the contingent features underlying these instruments had been fully triggered as of December 31, 2013 and December 31, 2012, Consolidated SCE&G could request $31.7 million and $32.1 million, respectively, of cash collateral from its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net asset position as of December 31, 2013 and December 31, 2012 is $31.7 million and $32.1 million, respectively.

Information related to Consolidated SCE&G's offsetting derivative assets follows:

Millions of dollars	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Received	Net Amount
As of December 31, 2013						
Interest rate	$32	—	$32	$(1)	—	$31
Balance sheet location	Prepayments and other		$13			
	Other deferred debits and other assets		19			
	Total		$32			
As of December 31, 2012						
Interest rate	$73	—	$73	$(17)	—	$56
Balance sheet location	Prepayments and other		$42			
	Other deferred debits and other assets		31			
	Total		$73			

Information related to Consolidated SCE&G's offsetting derivative liabilities follows:

Millions of dollars	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		
				Financial Instruments	Cash Collateral Posted	Net Amount
As of December 31, 2013						
Interest rate	$2	—	$2	$(1)	$1	$—
Balance sheet location	Other current liabilities		$2			
	Total		$2			
As of December 31, 2012						
Interest rate	$75	—	$75	$(17)	$35	$23
Balance sheet location	Other current liabilities		$66			
	Other deferred credits and other liabilities		9			

Total	$75

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7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

Consolidated SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value Level 2 measurements were as follows:

	As of December 31, 2013	As of December 31, 2012
Millions of dollars	Level 2	Level 2
Assets-Interest rate contracts	$32	$73
Liabilities-Interest rate contracts	2	75

There were no Level 1 or Level 3 fair value measurements for either period presented and there were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during the periods presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2013 and December 31, 2012 were as follows:

	As of December 31, 2013		As of December 31, 2012	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$4,054.9	$4,433.0	$3,722.0	$4,543.1

Fair values of long-term debt instruments are based on net present value calculations using independently sourced market data that incorporate a developed discount rate using similarly rated long-term debt, along with benchmark interest rates. As such, the aggregate fair values presented above are considered to be Level 2. Carrying values reflect the fair values of interest rate swaps designated as fair value hedges, based on discounted cash flow models with independently sourced market data. Early settlement of long-term debt may not be possible or may not be considered prudent.

Carrying values of short-term borrowings approximate their fair values, which are based on quoted prices from dealers in the commercial paper market. These fair values are considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees hired before January 1, 2014. In the third quarter of 2013, SCANA amended its pension plan such that benefits are no longer offered to employees hired or rehired after December 31, 2013, and pension benefits for existing participants will no longer accrue for services performed or compensation earned after December 31, 2023. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA's pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all employees hired from January 1, 2000 through December 31, 2013. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula and the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued except that participants under the cash balance formula will continue to earn interest credits.

In addition to pension benefits, SCE&G participates in SCANA's unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees hired before January 1, 2011 share in a portion of their medical care cost. Employees hired after December 31, 2010 are responsible for the full costs of retiree medical benefits elected by them. SCANA provides life insurance benefits to retirees at no charge, except that employees hired after December 31, 2010 are ineligible for retiree life insurance benefits. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans. The information presented below reflects Consolidated SCE&G's portion of the obligations, assets, funded status, net periodic benefit costs, and other information reported for the parent sponsored plans as a whole. The tabular data presented reflects the use of various cost assignment methodologies and participation assumptions based on Consolidated SCE&G's past and current employees and its share of plan assets.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2013	2012	2013	2012
Benefit obligation, January 1	$788.4	$705.0	$206.0	$178.4
Service cost	17.6	15.7	4.6	3.7
Interest cost	32.6	36.4	8.7	9.4
Plan participants’ contributions	—	—	2.0	2.3
Actuarial (gain) loss	(70.7)	80.3	(27.3)	26.2
Benefits paid	(50.6)	(49.0)	(9.3)	(10.8)
Curtailment	(21.6)	—	—	—
Amounts funded to parent	—	—	(3.0)	(3.2)
Benefit obligation, December 31	$695.7	$788.4	$181.7	$206.0

The accumulated benefit obligation for pension benefits was $673.2 million at the end of 2013 and $740.2 million at the end of 2012. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Annual discount rate used to determine benefit obligation	5.03%	4.10%	5.19%	4.19%
Assumed annual rate of future salary increases for projected benefit obligation	3.00%	3.75%	3.75%	3.75%

A 7.4% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation at December 31, 2013 by $1.0 million and at December 31, 2012 by $1.3 million. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation at December 31, 2013 by $0.9 million and 2012 by $1.2 million.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Fair value of plan assets	$792.1	$732.0	—	—
Benefit obligation	695.7	788.4	$181.7	$206.0

Funded status	$96.4	$(56.4)	$(181.7)	$(206.0)

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Amounts recognized on the consolidated balance sheets consist of:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Current liability	—	—	$(7.8)	$(8.5)
Noncurrent asset	$96.4	—	—	—
Noncurrent liability	—	$(56.4)	(173.9)	(197.5)

Amounts recognized in accumulated other comprehensive loss (a component of common equity) as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$1.8	$2.7	$0.6	$1.1
Prior service cost	0.2	0.2	—	—
Total	$2.0	$2.9	$0.6	$1.1

Amounts recognized in regulatory assets as of December 31, 2013 and 2012 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2013	2012	2013	2012
Net actuarial loss	$107.7	$257.5	$20.1	$46.7
Prior service cost	11.1	23.3	0.7	1.2
Transition obligation	—	—	—	0.1
Total	$118.8	$280.8	$20.8	$48.0

In connection with the joint ownership of Summer Station, as of December 31, 2013 and 2012, SCE&G recorded within deferred debits $14.1 million and $26.8 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2013 and 2012, SCE&G also recorded within deferred debits $12.6 million and $14.7 million, respectively, from Santee Cooper, representing its portion of the unfunded postretirement benefit obligation.

Changes in Fair Value of Plan Assets

	Pension Benefits	
Millions of dollars	2013	2012
Fair value of plan assets, January 1	$732.0	$695.3
Actual return on plan assets	110.7	85.7
Benefits paid	(50.6)	(49.0)
Fair value of plan assets, December 31	$792.1	$732.0

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the obligations of the pension plan, (2) overseeing the plan's investments in an asset-liability framework that considers the funding surplus (or deficit) between assets and liabilities, and overall risk associated with assets as compared to liabilities, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan is closed to new entrants effective January 1, 2014, and benefit accruals will cease effective January 1, 2024. In addition, during 2013, SCANA adopted a dynamic investment strategy for the management of the pension plan assets. The strategy will lead to a reduction in equities and an increase in long duration fixed income allocations over time with the intention of reducing volatility of funded status and pension costs in connection with the amendments to the plan.

The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, levels of diversification, investment managers and performance expectations. The total portfolio is constructed and maintained to provide prudent diversification with regard to the concentration of holdings in individual issues, corporations, or industries.

Transactions involving certain types of investments are prohibited. These include, except where utilized by a hedge fund manager, any form of private equity; commodities or commodity contracts (except for unleveraged stock or bond index futures and currency futures and options); ownership of real estate in any form other than publicly traded securities; short sales, warrants or margin transactions, or any leveraged investments; and natural resource properties. Investments made for the purpose of engaging in speculative trading are also prohibited.

The pension plan asset allocation at December 31, 2013 and 2012 and the target allocation for 2014 are as follows:

	Percentage of Plan Assets					
	Target Allocation		At December 31,			
Asset Category	2014		2013		2012	
Equity Securities	58	%	59	%	66	%
Fixed Income	33	%	32	%	25	%
Hedge Funds	9	%	9	%	9	%

For 2014, the expected long-term rate of return on assets will be 8.00%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, considers the expected active returns across various asset classes and assumes an asset allocation of 58% with equity managers, 33% with fixed income managers and 9% with hedge fund managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate. Additional rebalancing may occur subject to funded status improvements as part of the dynamic investment policy adopted for 2014.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2013 and 2012, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements at Reporting Date Using							
Millions of dollars	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3
	December 31, 2013				December 31, 2012			
Common stock	$302	$302			$292	$292		
Preferred stock	1	1			1	1		
Mutual funds	278	18	$260		226	12	$214	
Short-term investment vehicles	18		18		18		18	
US Treasury securities	30		30		38		38	
Corporate debt securities	48		48		52		52	
Loans secured by mortgages	11		11		10		10	
Municipals	3		3		4		4	
Limited partnerships	32	1	31		27	1	26	
Multi-strategy hedge funds	69			$69	64			$64
	$792	$322	$401	$69	$732	$306	$362	$64

There were no transfers of fair value amounts into or out of Levels 1, 2 or 3 during 2013 or 2012.

The pension plan values common stock, preferred stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as NYSE and NASDAQ, where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds represent investments in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The fair value of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Level 3	
Millions of dollars	2013	2012
Beginning Balance	$64	$60
Unrealized gains included in changes in net assets	5	4
Purchases, issuances, and settlements	—	—
Transfers in or out of Level 3	—	—
Ending Balance	$69	$64

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G’s assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits
2014	$61.5	$9.3
2015	61.2	10.0
2016	63.8	10.6
2017	65.8	11.1
2018	66.1	11.6
2019 - 2023	338.4	65.1

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and as a result of closing the plan to new entrants and freezing benefit accruals in the future, SCE&G does not anticipate making significant contributions to the pension plan for the foreseeable future.

Net Periodic Benefit Cost

SCE&G records net periodic benefit cost utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
Millions of dollars	2013	2012	2011	2013	2012	2011
Service cost	$17.6	$15.7	$14.7	$4.6	$3.7	$3.4
Interest cost	32.6	36.4	37.0	8.7	9.4	9.6
Expected return on assets	(51.9)	(50.4)	(54.2)	n/a	n/a	n/a
Prior service cost amortization	5.0	6.0	6.0	0.6	0.7	0.8
Amortization of actuarial losses	14.3	15.6	10.4	2.6	1.1	0.3
Curtailment	8.4	—	—	—	—	—
Transition obligation amortization	—	—	—	—	—	(0.1)
Net periodic benefit cost	$26.0	$23.3	$13.9	$16.5	$14.9	$14.0

Prior to July 15, 2010, the SCPSC allowed SCE&G to defer as a regulatory asset the amount of pension cost exceeding amounts included in rates for its retail electric and gas distribution regulated operations. In connection with the SCPSC's July 2010 electric rate order and November 2010 natural gas RSA order, SCE&G began deferring, as a regulatory asset, all pension costs related to retail electric and gas operations that otherwise would have been charged to expense. Effective in January 2013, in connection with the December 2012 rate order, SCE&G began amortizing previously deferred pension cost related to retail electric operations totaling approximately $63 million over approximately 30 years (see Note 2) and recovering current pension costs related to retail electric operations through a rate rider that may be adjusted annually. Similarly, in connection with the October 2013 RSA order, deferred pension cost related to gas operations of approximately $14 million is being amortized over approximately 14 years, and effective November 2013, SCE&G is recovering current pension expense related to gas operations through cost of service rates (see Note 2).

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits				Other Postretirement Benefits		
Millions of dollars	2013	2012		2011	2013	2012	2011
Current year actuarial (gain) loss	$(0.8)	$0.4		$0.7	$(0.4)	$0.7	—$0.1
Amortization of actuarial losses	(0.1)	(0.1)		(0.1)	(0.1)	—	——
Amortization of prior service cost	—	(0.1)	—	(0.1)	—	(0.1)	——
Prior service cost (credit)	—	—	400,000	—	—	—	——
Amortization of transition obligation	—	—	—	—	—	—	—
Total recognized in other comprehensive income (loss)	$(0.9)	$0.2	400,000	$0.5	$(0.5)	$0.6	$0.1

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits				Other Postretirement Benefits		
Millions of dollars	2013	2012		2011	2013	2012	2011
Current year actuarial (gain) loss	$(137.1)	$37.9		$61.8	$(24.4)	$25.7	—$5.0

Amortization of actuarial losses	(12.7)	(14.0)		(9.3)	(2.2)	(1.0)	—(0.2)
Amortization of prior service cost	(4.5)	(5.7)	—	(5.5)	(0.5)	(0.7)	—(0.7)
Prior service cost (credit)	(7.7)	—	400,000	—	—	—	—
Amortization of transition obligation	—	—	—	—	(0.1)	(0.2)	(0.2)
Total recognized in regulatory assets	$(162.0)	$18.2		$47.0	$(27.2)	$23.8	$3.9

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Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.10%/5.07%	5.25 %	5.56 %	4.19 %	5.35 %	5.72 %
Expected return on plan assets	8.00 %	8.25 %	8.25 %	n/a	n/a	n/a
Rate of compensation increase	3.75%/3.00%	4.00 %	4.00 %	3.75 %	4.00 %	4.00 %
Health care cost trend rate	n/a	n/a	n/a	7.80 %	8.20 %	8.00 %
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00 %	5.00 %	5.00 %
Year achieved	n/a	n/a	n/a	2020	2020	2017

Net periodic benefit cost for the period through September 1, 2013, was determined using a 4.10% discount rate, and net periodic benefit cost after that date was determined using a 5.07% discount rate. Similarly, estimated rates of compensation increase were changed in connection with the September 1, 2013 remeasurement.

The actuarial loss and prior service cost to be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2014 are insignificant.

The estimated amounts to be amortized from regulatory assets into net periodic benefit cost in 2014 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$ 3.7	$ 0.3
Prior service cost	3.1	0.3
Total	$ 6.8	$ 0.6

Other postretirement benefit costs are subject to annual per capita limits pursuant to the plan's design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is not significant.

Stock Purchase Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may defer up to 75% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee’s eligible earnings. Total matching contributions made to the plan for 2013, 2012 and 2011 were $18.7million, $17.7 million and $17.3 million, respectively, and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the LTECP which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The LTECP currently authorizes the issuance of up to five million shares of SCANA’s common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation costs related to share-based payment transactions are required to be recognized in the financial statements. With limited exceptions, including those liability awards discussed below, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award. Share-based payment awards do not have non-forfeitable rights to dividends or dividend equivalents. To the extent that the awards themselves do not vest, dividends or dividend equivalents which would have been paid on those awards do not vest.

Liability Awards

The 2011-2013, 2012-2014, and 2013-2015 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each of the performance cycles, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of retirement or termination of employment prior to the end of the cycle, subject to exceptions for death, disability or change in control. The remaining 80% of the award was granted in performance shares. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock. Dividend equivalents are accrued on the performance shares and the restricted share units. Payouts of performance share awards are determined by SCANA's performance against pre-determined measures of TSR as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%).

Compensation cost of liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Awards under the 2011-2013 performance cycle were paid in cash at SCANA's discretion in February 2014. Cash-settled liabilities related to prior program cycles were paid totaling approximately $3.2 million in 2013, $8.7 million in 2012 and $2.5 million in 2011.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling $5.5 million in 2013, $9.5 million in 2012 and $4.0 million in 2011. Fair value adjustments resulted in capitalized compensation costs of $0.5 million in 2013, $2.1 million in 2012 and $0.2 million in 2011.

Equity Awards

No equity awards were made during any period presented, and the effects of previous such awards on Consolidated SCE&G's results of operations, cash flows and financial position were not significant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the company's nuclear power plant. Price-Anderson provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $127.3 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $18.9 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $84.8 million per incident, but not more than $12.6 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer Station Unit 1 for property damage and outage costs up to $2.75 billion resulting from an event of nuclear origin. In addition, a builder's risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the owners of the New Units up to $500 million in limits of accidental property damage occurring during construction. The NEIL policies, in the aggregate, are subject to a maximum loss of $2.75 billion for any single loss occurrence. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the retrospective premium assessment would not exceed $41.6 million

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the Consolidated SCE&G's results of operations, cash flows and financial position.

New Nuclear Construction

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted with the Consortium for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $5.4 billion for plant and related transmission infrastructure costs, and is projected based on historical one-year and five-year escalation rates as required by the SCPSC.

SCE&G's current ownership share in the New Units is 55%. Under an agreement signed in January 2014 (and subject to customary closing conditions, including necessary regulatory approvals), SCE&G has agreed to acquire an additional 5% ownership in the New Units. Under the terms of this agreement SCE&G will acquire a 1% ownership interest in the New Units at the commercial operation date of Unit 2, will acquire an additional 2% ownership interest no later than the first anniversary of such commercial operation date, and will acquire the final 2% no later than the second anniversary of such commercial operation date. Under the terms of the agreement SCE&G has agreed to pay an amount equal to Santee Cooper's actual cost of the percentage conveyed as of the date of conveyance, which SCE&G estimates will be approximately $500 million for the entire 5% interest. In addition, the agreement provides that Santee Cooper will not transfer any of its remaining interest in the New Units to third parties until the New Units are complete. This transaction will not affect the payment obligations between the parties during construction for the New Units, nor is it anticipated that the payments would be reflected in a revised rates filing under the BLRA.

The Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both New Units. All sub-modules for CA20 have been received on site and its fabrication is underway. CA20 is expected to be ready for placement on the nuclear island of the first New Unit in the first quarter of 2014. In addition, the delivery schedule of sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be ready for placement on the nuclear island of the first New Unit during the third quarter of 2014. With this schedule, the Consortium continues to indicate that the substantial completion of the first New Unit is expected to be late 2017 or the first quarter of 2018 and that the substantial completion of the second New Unit is expected to be approximately twelve months after that of the first New Unit. The substantial completion dates currently approved by the SCPSC for the first and second New Units are March 15, 2017 and May 15, 2018, respectively. The SCPSC has also approved an 18-month contingency period beyond each of these dates. The preliminary expected new substantial completion dates are within the contingency periods. SCE&G cannot predict with certainty the extent to which the issue with the sub-modules or the delays in the substantial completion of the New Units will result in increased project costs. However, the preliminary estimate of the delay-related costs associated with SCE&G's 55% share of the New Units is approximately $200 million. SCE&G has not accepted responsibility for any of these delay-related costs and expects to have further discussions with the Consortium regarding such responsibility. Additionally, the EPC Contract provides for liquidated damages in the event of a delay in the completion of the New Units, which will also be included in discussions with the Consortium. SCE&G believes its responsibility for any portion of the $200 million estimate should ultimately be substantially less, once all of the relevant factors are considered.

In addition to the above-described project delays, SCE&G is also aware of financial difficulties at a supplier responsible for certain significant components of the project. The Consortium is monitoring the potential for disruptions in such equipment fabrication and possible responses. Any disruptions could impact the project's schedule or costs, and such impacts could be material.

The parties to the EPC Contract have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities

under the EPC Contract, issues have materialized that impact project budget and schedule. Claims specifically relating to COL delays,
design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock
conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. The resolution
of these specific claims is discussed in Note 2. SCE&G expects to resolve any disputes that arise in the future, including any which may arise with respect to the delay-related costs discussed above, through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

During the fourth quarter of 2013, the Consortium began a full re-baselining of the Unit 2 and Unit 3 construction schedules to incorporate a more detailed evaluation of the engineering and procurement activities necessary to accomplish the schedule and to provide a detailed reassessment of the impact of the revised Unit 2 and Unit 3 schedules on engineering and design resource allocations, procurement schedules, construction work crew assignments, and other items. The result will be a revised fully integrated construction schedule that will provide detailed and itemized information on individual budget and cost categories, cost estimates at completion for all non-firm and fixed scopes of work, and the timing of specific construction activities and cash flow requirements. SCE&G anticipates that the revised schedule and the cost estimate at completion for all non-firm and fixed scopes of work will be finalized in the third quarter of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of the new schedule.

When the NRC issued the COLs for the New Units, two of the conditions that it imposed were requiring inspection and testing of certain components of the New Units' passive cooling system, and requiring the development of strategies to respond to extreme natural events resulting in the loss of power at the New Units. In addition, the NRC directed the Office of New Reactors to issue to SCE&G an order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing. These conditions and requirements are responsive to the NRC's Near-Term Task Force report titled “Recommendations for Enhancing Reactor Safety in the 21st Century.” This report was prepared in the wake of the March 2011 earthquake-generated tsunami, which severely damaged several nuclear generating units and their back-up cooling systems in Japan. SCE&G continues to evaluate the impact of these conditions and requirements that may be imposed on the construction and operation of the New Units, and SCE&G, pursuant to the license condition, prepared and submitted an integrated response plan for the New Units to the NRC in August 2013. SCE&G cannot predict what additional regulatory or other outcomes may be implemented in the United States, or how such initiatives would impact SCE&G's existing Summer Station or the construction or operation of the New Units.

Subject to a national megawatt capacity limitation, the electricity to be produced by the New Units (advanced nuclear units, as defined) is expected to qualify for nuclear production tax credits under Section 45J of the Internal Revenue Code. Following the pouring of safety-related concrete for each of the New Units’ reactor buildings (March 2013 for the first New Unit and November 2013 for the second New Unit), SCE&G has applied to the IRS for its allocations of such national megawatt capacity limitation. The IRS will forward the applications to the DOE for appropriate certification.

Environmental

As part of the President's Climate Action Plan and by Presidential Memorandum issued June 25, 2013, the EPA was directed to issue a revised carbon standard for new power plants by re-proposing NSPS under the CAA for emissions of carbon dioxide from newly constructed fossil fuel-fired units. The rule became final on January 8, 2014 and requires all new fossil fuel-fired power plants to meet the carbon dioxide emissions profile of a combined cycle natural gas plant. While most new natural gas plants will not be required to include any new technologies, no new coal-fired plants could be constructed without carbon capture and sequestration capabilities. Consolidated SCE&G is evaluating the final rule, but does not plan to construct new coal-fired units in the near future. The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units by June 1, 2014, to be made final no later than June 1, 2015. Consolidated SCE&G also cannot predict when rules will become final for existing units, if at all, or what conditions they may impose on Consolidated SCE&G, if any. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

From a regulatory perspective, SCE&G and GENCO continually monitor and evaluate their current and projected emission levels and strive to comply with all state and federal regulations regarding those emissions. SCE&G and GENCO participate in the sulfur dioxide and nitrogen oxide emission allowance programs with respect to coal plant emissions and also have constructed additional pollution control equipment at several larger coal-fired electric generating plants. Further, SCE&G is engaged in construction activities of the New Units which are expected to reduce GHG emission levels significantly once they are completed and dispatched by potentially displacing some of the current coal-fired generation sources. These actions are expected to address many of the rules and regulations discussed below.

In 2005, the EPA issued the CAIR, which required the District of Columbia and 28 states to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G and GENCO determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the CSAPR. This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and is aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. On August 21, 2012, the Court of Appeals vacated CSAPR and left CAIR in place. The EPA's petition for rehearing of the Court of Appeals' order was denied. In June 2013 the U.S. Supreme Court agreed to review the Court of Appeals' decision and oral arguments were held on December 10, 2013. A decision is still pending. Air quality control installations that SCE&G and GENCO have already completed have allowed Consolidated SCE&G to comply with the reinstated CAIR and will also allow it to comply with CSAPR, if reinstated. Consolidated SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with such regulations are expected to be recoverable through rates.

In April 2012, the EPA's rule containing new standards for mercury and other specified air pollutants became effective. The rule provides up to four years for facilities to meet the standards, and Consolidated SCE&G's evaluation of the rule is ongoing. SCE&G's decision in 2012 to retire certain coal-fired units or convert them to burn natural gas and its project to build the New Units (see Note 1) along with other actions are expected to result in Consolidated SCE&G's compliance with the EPA's rule. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

The CWA provides for the imposition of effluent limitations that require treatment for wastewater discharges. Under the CWA, compliance with applicable limitations is achieved under state-issued NPDES permits. As a facility’s NPDES permit is renewed (every five years), any new effluent limitations would be incorporated. The ELG Rule was published in the Federal Register on June 7, 2013, and is expected to be finalized May 22, 2014. The EPA expects compliance as soon as possible after July 2017 but no later than July 2020.

Additionally, the EPA is expected to issue a rule that modifies requirements for existing cooling water intake structures in early 2014. Consolidated SCE&G is conducting studies and is developing or implementing compliance plans for these initiatives. Congress is expected to consider further amendments to the CWA. Such legislation may include toxicity-based standards as well as limitations to mixing zones. These provisions, if passed, could have a material impact on the financial condition, results of operations and cash flows of SCE&G and GENCO. Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

In response to a federal court order to establish a definite timeline for a CCR rule, the EPA has said it will issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 2014. Such regulations could result in the treatment of some CCRs as hazardous waste and could impose significant costs to utilities, such as SCE&G and GENCO. While Consolidated SCE&G cannot predict how extensive the regulations will be, Consolidated SCE&G believes that any additional costs imposed by such regulations would be recoverable through rates.

The Nuclear Waste Act required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998. The Nuclear Waste Act also imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. SCE&G entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. As of December 31, 2013, the federal government has not accepted any spent fuel from Summer Station Unit 1, and it remains unclear when the repository may become available. SCE&G has on-site spent nuclear fuel storage capability in its existing fuel pool until at least 2017, and has commenced construction of a dry cask storage facility to accommodate the spent nuclear fuel output for the life of Summer Station Unit 1. SCE&G may evaluate other technology as it becomes available.

The provisions of CERCLA authorize the EPA to require the clean-up of hazardous waste sites. In addition, the state of South Carolina has similar laws. SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. In addition, regulators from the EPA and other federal or state agencies periodically notify SCE&G that it may be required to perform or participate in the investigation and remediation of a hazardous waste site. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures may differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Such amounts are recorded in regulatory assets and amortized, with recovery provided through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by DHEC and the EPA. SCE&G anticipates that major remediation activities at all these sites will continue until 2017 and will cost an additional $20.2 million, which is accrued in Other within Deferred Credits and Other Liabilities on the consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At December 31, 2013, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.7 million and are included in regulatory assets.

Claims and Litigation

Consolidated SCE&G is engaged in various claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on Consolidated SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

Consolidated SCE&G is obligated under various operating leases for vehicles, office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $13.6 million in 2013, $9.6 million in 2012 and $10.8 million in 2011. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2014	$ 4
2015	3
2016	2
2017	1
2018	1
Thereafter	19
Total	$ 30

Asset Retirement Obligations

Consolidated SCE&G recognizes a liability for the present value of an ARO when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to Consolidated SCE&G's regulated utility operations. As of December 31, 2013, Consolidated SCE&G has recorded AROs of approximately $191 million for nuclear plant decommissioning (see Note 1) and AROs of approximately $356 million for other conditional obligations primarily related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2013	2012
Beginning balance	$535	$450
Liabilities incurred	5	—
Liabilities settled	(4)	(5)
Accretion expense	24	23
Revisions in estimated cash flows	(13)	67
Ending Balance	$547	$535

11. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $33.3 million in 2013, $35.9 million in 2012 and $30.8 million in 2011.

SCE&G had approximately $3.3 million and $3.4 million payable to CGT for transportation services at December 31, 2013 and December 31, 2012, respectively. SCE&G had approximately $1.3 million receivable from CGT for transportation services at December 31, 2013 and an insignificant receivable amount at December 31, 2012.

SCE&G purchases natural gas and related pipeline capacity from SEMI to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $166.9 million in 2013, $125.5 million in 2012 and $187.4 million in 2011. SCE&G's payables to SEMI for such purposes were $12.5 million and $13.1 million as of December 31, 2013 and 2012, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC which is involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's payable to this affiliate was $18.0 million at December 31, 2013 and $1.8 million at December 31, 2012. SCE&G's total purchases to this affiliate were $134.2 million in 2013 and $111.6 million in 2012. SCE&G's total sales to this affiliate were $133.6 million in 2013 and $111.1 million in 2012.

An affiliate processes and pays invoices for Consolidated SCE&G and is reimbursed. Consolidated SCE&G owed $49.1 million and $39.4 million to the affiliate at December 31, 2013 and 2012, respectively, for invoices paid by the affiliate on its behalf.

SCANA Services provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, customer services, marketing and sales, human resources, corporate compliance, purchasing, financial services, risk management, public affairs, legal services, investor relations, gas supply and capacity management, strategic planning, and general administrative services. Costs for these services totaled $285.6 million in 2013, $305.6 million in 2012 and $302.6 million in 2011.

12. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G's reportable segments follow the same accounting policies as those described in Note 1.

Electric Operations is primarily engaged in the generation, transmission, and distribution of electricity, and is regulated by the SCPSC and FERC. Gas Distribution is engaged in the purchase and sale, primarily at retail, of natural gas, and is regulated by the SCPSC.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Consolidated Total
2013				
External Revenue	$2,431	$414	—	$2,845
Operating Income	679	58	—	737
Interest Expense	19	—	$198	217
Depreciation and Amortization	294	26	(7)	313
Segment Assets	9,488	686	2,526	12,700
Expenditures for Assets	907	45	51	1,003
Deferred Tax Assets	10	n/a	(10)	—
2012				
External Revenue	$2,453	$356	—	$2,809
Operating Income	668	49	—	717
Interest Expense	21	—	$190	211
Depreciation and Amortization	278	25	(10)	293
Segment Assets	8,989	659	2,456	12,104
Expenditures for Assets	999	56	(77)	978
Deferred Tax Assets	9	n/a	(9)	—
2011				
External Revenue	$2,432	$387	—	$2,819
Operating Income	616	40	$(2)	654
Interest Expense	23	—	181	204
Depreciation and Amortization	271	25	(10)	286
Segment Assets	8,222	622	2,193	11,037
Expenditures for Assets	806	60	(18)	848
Deferred Tax Assets	9	n/a	(1)	8

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, Consolidated SCE&G does not allocate interest charges, income tax expense, earnings available to common shareholder or assets other than utility plant to its segments. Intersegment revenue and interest income were not significant. Consolidated SCE&G's deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The consolidated financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to asset retirement obligations, and totals not allocated to other segments.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Millions of dollars	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2013					
Total operating revenues	$728	$696	$776	$645	$2,845
Operating income	191	180	255	111	737
Net Income	92	88	139	72	391
Earnings Available to Common Shareholder	89	85	136	70	380
2012					
Total operating revenues	$663	$661	$777	$708	$2,809
Operating income	156	165	241	155	717
Net Income	72	78	132	70	352
Earnings Available to Common Shareholder	69	76	129	67	341

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

Not Applicable.

ITEM 9A. CONTROLS AND PROCEDURES

SCANA:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCANA’s management, including the CEO and CFO, of the effectiveness of the design and operation of SCANA’s disclosure controls and procedures. For purposes of this evaluation, disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by SCANA in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to SCANA’s management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, SCANA’s management, including the CEO and CFO, concluded that SCANA’s disclosure controls and procedures were effective as of December 31, 2013.

Management’s Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCANA’s management, including the CEO and CFO, of any change in SCANA's internal controls over financial reporting during the quarter ended December 31, 2013. There has been no change in SCANA’s internal controls over financial reporting during the quarter ended December 31, 2013 that has materially affected or is reasonably likely to materially affect SCANA’s internal control over financial reporting.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and that it has assessed, as of December 31, 2013, the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCANA is responsible for establishing and maintaining adequate internal control over financial reporting. SCANA’s internal control system was designed by or under the supervision of SCANA’s management, including the CEO and CFO, to provide reasonable assurance to SCANA’s management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCANA’s management assessed the effectiveness of SCANA’s internal control over financial reporting as of December 31, 2013. In making this assessment, SCANA used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework (1992). Based on this assessment, SCANA's management believes that, as of December 31, 2013, internal control over financial reporting is effective based on those criteria.

SCANA's independent registered public accounting firm has issued an attestation report on SCANA's internal control over financial reporting. This report follows.

ATTESTATION REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
SCANA Corporation
Cayce, South Carolina

We have audited the internal control over financial reporting of SCANA Corporation and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December

31, 2013, of the Company and our report dated February 28, 2014, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/DELOITTE & TOUCHE LLP
Charlotte, North Carolina
February 28, 2014

SCE&G:

Evaluation of Disclosure Controls and Procedures:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCE&G's management, including the CEO and CFO, of the effectiveness of the design and operation of SCE&G's disclosure controls and procedures. For purposes of this evaluation, disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by SCE&G in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to SCE&G's management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, SCE&G's management, including the CEO and CFO, concluded that SCE&G's disclosure controls and procedures were effective as of December 31, 2013.

Management's Evaluation of Internal Control Over Financial Reporting:

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of SCE&G's management, including the CEO and CFO, of any change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2013. There has been no change in SCE&G's internal controls over financial reporting during the quarter ended December 31, 2013 that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, management is required to include in this Form 10-K an internal control report wherein management states its responsibility for establishing and maintaining adequate internal control structure and procedures for financial reporting and that it has assessed, as of December 31, 2013, the effectiveness of such structure and procedures. This management report follows.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of SCE&G is responsible for establishing and maintaining adequate internal control over financial reporting. SCE&G's internal control system was designed by or under the supervision of SCE&G's management, including the CEO and CFO, to provide reasonable assurance to SCE&G's management and board of directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of the internal control over financial reporting may deteriorate in future periods due to either changes in conditions or declining levels of compliance with policies or procedures.

SCE&G's management assessed the effectiveness of SCE&G's internal control over financial reporting as of December 31, 2013. In making this assessment, SCE&G used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (1992). Based on this assessment, SCE&G's management believes that, as of December 31, 2013, internal control over financial reporting is effective based on those criteria.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

SCANA: A list of SCANA's executive officers is in Part I of this annual report at page 25. The other information required by Item 10 is incorporated herein by reference to the captions "NOMINEES FOR DIRECTORS," "CONTINUING DIRECTORS," "BOARD MEETINGS-COMMITTEES OF THE BOARD", "GOVERNANCE INFORMATION-SCANA's Code of Conduct & Ethics" and "OTHER INFORMATION-Section 16(a) Beneficial Ownership Reporting Compliance" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 11. EXECUTIVE COMPENSATION

SCANA: The information required by Item 11 is incorporated herein by reference to the captions "Compensation Committee Interlocks and Insider Participation," "Compensation Discussion and Analysis," Compensation Committee Report," "Summary Compensation Table," "2013 Grants of Plan-Based Awards," "Outstanding Equity Awards at 2013 Fiscal Year-End," "2013 Option Exercises and Stock Vested," "Pension Benefits," "2013 Nonqualified Deferred Compensation," and "Potential Payments Upon Termination or Change in Control," under the heading "EXECUTIVE COMPENSATION" and the heading "DIRECTOR COMPENSATION" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

SCANA: Information required by Item 12 is incorporated herein by reference to the caption "SHARE OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

Equity securities issuable under SCANA's compensation plans at December 31, 2013 are summarized as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders:	-		

Long-Term Equity Compensation Plan	n/a	n/a	3,138,638
Non-Employee Director Compensation Plan	n/a	n/a	100,886
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	n/a	n/a	3,239,524

SCE&G: Not applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

SCANA: The information required by Item 13 is incorporated herein by reference to the caption "RELATED PARTY TRANSACTIONS" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: Not applicable.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

SCANA: The information required by Item 14 is incorporated herein by reference to "PROPOSAL 2-APPROVAL OF THE APPOINTMENT OF THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM" in SCANA's definitive proxy statement for the 2014 annual meeting of shareholders which will be filed with the SEC pursuant to Regulation 14A, promulgated under the Securities and Exchange Act of 1934 within 120 days after the end of SCANA's fiscal year.

SCE&G: The Audit Committee Charter requires the Audit Committee to pre-approve all auditing services and permitted non-audit services (including the fees and terms thereof) to be performed by the independent registered accounting firm. Pursuant to a policy adopted by the Audit Committee, its Chairman may pre-approve the rendering of services on behalf of the Audit Committee. Decisions by the Chairman to pre-approve the rendering of services are presented to the Audit Committee at its next scheduled meeting.

Independent Registered Public Accounting Firm's Fees

The following table sets forth the aggregate fees, all of which were approved by the Audit Committee, charged to SCE&G and its consolidated affiliates for the fiscal years ended December 31, 2013 and 2012 by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates.

	2013	2012
Audit Fees (1)	$1,972,696	$1,772,129
Audit-Related Fees (2)	115,706	258,357
Total Fees	$2,088,402	$2,030,486

(1) Fees for audit services billed in 2013 and 2012 consisted of audits of annual financial statements, comfort letters, statutory and regulatory audits, consents and other services related to SEC filings, and accounting research.

(2) Fees primarily for employee benefit plan audits and, in 2012, for non-statutory audit services.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed or furnished as a part of this Form 10-K:

(1) Financial Statements and Schedules:

The Report of Independent Registered Public Accounting Firm on the financial statements for each of SCANA and SCE&G is listed under Item 8 herein.

The financial statements and supplementary financial data filed as part of this report for SCANA and SCE&G are listed under Item 8 herein.

The financial statement schedules "Schedule II - Valuation and Qualifying Accounts" filed as part of this report for SCANA and SCE&G are included below.

(2) Exhibits

Exhibits required to be filed or furnished with this Annual Report on Form 10-K are listed in the Exhibit Index following the signature page. Certain of such exhibits which have heretofore been filed with the SEC and which are designated by reference to their exhibit number in prior filings are incorporated herein by reference and made a part hereof.

Pursuant to Rule 15d-21 promulgated under the Securities Exchange Act of 1934, the annual report for SCANA's employee stock purchase plan will be furnished under cover of Form 11-K to the SEC when the information becomes available.

As permitted under Item 601(b)(4)(iii) of Regulation S-K, instruments defining the rights of holders of long-term debt of less than 10% of the total consolidated assets of SCANA, for itself and its subsidiaries and of SCE&G, for itself and its consolidated affiliates, have been omitted and SCANA and SCE&G agree to furnish a copy of such instruments to the SEC upon request.

Schedule II—Valuation and Qualifying Accounts
(in millions)

Description	Beginning Balance	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions from Reserves	Ending Balance
SCANA:					
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts					
2013	$ 7	$13	—	$ 14	$6
2012	6	14	—	13	7
2011	9	17	—	20	6
Reserves other than those deducted from assets on the balance sheet:					
Reserve for injuries and damages					
2013	$ 6	$4	—	$ 4	$6
2012	6	4	—	4	6
2011	5	4	—	3	6
SCE&G:					
Reserves deducted from related assets on the balance sheet:					
Uncollectible accounts					
2013	$ 3	$7	—	$ 7	$3
2012	3	6	—	6	3
2011	3	6	—	6	3
Reserves other than those deducted from assets on the balance sheet:					
Reserve for injuries and damages					
2013	$ 5	$3	—	$ 3	$5
2012	4	3	—	2	5
2011	4	2	—	2	4

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SCANA CORPORATION

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, President, Chief
Executive Officer, Chief Operating Officer and Director

DATE: February 28, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries thereof.

/s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, President, Chief Executive
Officer, Chief Operating Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison
J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	L. M. Miller
J. F. A. V. Cecil	J. W. Roquemore
D. M. Hagood	M. K. Sloan
J. W. Martin, III	H. C. Stowe
J. M. Micali	A. Trujillo

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 28, 2014

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries or consolidated affiliates thereof.
SOUTH CAROLINA ELECTRIC & GAS COMPANY

BY: /s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive Officer and Director

DATE: February 28, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to the registrant and any subsidiaries or consolidated affiliates thereof.
/s/ K. B. Marsh
K. B. Marsh, Chairman of the Board, Chief Executive
Officer and Director
(Principal Executive Officer)

/s/ J. E. Addison
J. E. Addison
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ J. E. Swan, IV
J. E. Swan, IV
Controller
(Principal Accounting Officer)

Other Directors*:

J. A. Bennett	J. W. Roquemore
D. M. Hagood	M. K. Sloan
J. M. Micali	H. C. Stowe
L. M. Miller	

* Signed on behalf of each of these persons by Ronald T. Lindsay, Attorney-in-Fact

DATE: February 28, 2014

EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-K of SCANA	SCE&G	Description
3.01	X		Restated Articles of Incorporation of SCANA, as adopted on April 26, 1989 (Filed as Exhibit 3-A to Registration Statement No. 33-49145 and incorporated by reference herein)
3.02	X		Articles of Amendment dated April 27, 1995 (Filed as Exhibit 4-B to Registration Statement No. 33-62421 and incorporated by reference herein)
3.03	X		Articles of Amendment effective April 25, 2011 (Filed as Exhibit 4.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.04		X	Restated Articles of Incorporation of SCE&G, as adopted on December 30, 2009 (Filed as Exhibit 1 to Form 8-A (File No. 000-53860) and incorporated by reference herein)
3.05	X		By-Laws of SCANA as amended and restated as of February 19, 2009 (Filed as Exhibit 4.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
3.06		X	By-Laws of SCE&G as revised and amended on February 22, 2001 (Filed as Exhibit 3.05 to Registration Statement No. 333-65460 and incorporated by reference herein)
4.01	X	X	Articles of Exchange of SCE&G and SCANA (Filed as Exhibit 4-A to Post-Effective Amendment No. 1 to Registration Statement No. 2-90438 and incorporated by reference herein)
4.02	X		Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N. A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 4-A to Registration No. 33-32107 and incorporated by reference herein)
4.03	X		First Supplemental Indenture dated as of November 1, 2009 to Indenture dated as of November 1, 1989 between SCANA and The Bank of New York Mellon Trust Company, N.A. (successor to The Bank of New York), as Trustee (Filed as Exhibit 99.01 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.04	X		Junior Subordinated Indenture dated as of November 1, 2009 between SCANA and U.S. Bank National Association, as Trustee (Filed as Exhibit 99.02 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.05	X		First Supplemental Indenture to Junior Subordinated Indenture referred to in Exhibit 4.04 dated as of November 1, 2009 (Filed as Exhibit 99.03 to Registration Statement No. 333-174796 and incorporated by reference herein)
4.06		X	Indenture dated as of April 1, 1993 from SCE&G to The Bank of New York Mellon Trust Company, N. A. (as successor to NationsBank of Georgia, National Association), as Trustee (Filed as Exhibit 4-F to Registration Statement No. 33-49421 and incorporated by reference herein)
4.07		X	First Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 1, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-49421 and incorporated by reference herein)
4.08		X	Second Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of June 15, 1993 (Filed as Exhibit 4-G to Registration Statement No. 33-57955 and incorporated by reference herein)

4.09	X	Third Supplemental Indenture to Indenture referred to in Exhibit 4.06 dated as of September 1, 2013 (Filed as Exhibit 4.12 to Post-Effective Amendment to Registration Statement No. 333-184426-01 and incorporated by reference herein)

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10.01	X	X	Engineering, Procurement and Construction Agreement, dated May 23, 2008, between SCE&G, for itself and as Agent for the South Carolina Public Service Authority and a Consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2008 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.02	X	X	Contract for AP1000 Fuel Fabrication and Related Services between Westinghouse Electric Company LLC and SCE&G for V. C. Summer AP1000 Nuclear Plant Units 2 & 3 (portions of the exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended) (Filed as Exhibit 10.01 to Form 10-Q/A for the quarter ended June 30, 2011 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
*10.03	X	X	SCANA Executive Deferred Compensation Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.04 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.04	X	X	SCANA Supplemental Executive Retirement Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.05	X	X	SCANA Director Compensation and Deferral Plan (including amendments through April 21, 2011) (Filed as Exhibit 4.05 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.06	X	X	SCANA Long-Term Equity Compensation Plan as amended and restated (including amendments through December 31, 2009) (Filed as Exhibit 99.06 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.07	X	X	SCANA Supplementary Executive Benefit Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.07 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.08	X	X	SCANA Short-Term Annual Incentive Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.08 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.09	X	X	SCANA Supplementary Key Executive Severance Benefits Plan (including amendments through December 31, 2009) (Filed as Exhibit 99.09 to Registration Statement No. 333-174796 and incorporated by reference herein)
*10.10	X	X	Description of SCANA Whole Life Option (Filed as Exhibit 10-F for the year ended December 31, 1991, under cover of Form SE (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.11		X	Service Agreement between SCE&G and SCANA Services, Inc., effective January 1, 2004 (Filed as Exhibit 99.10 to Registration Statement No. 333-174796 and incorporated by reference herein)
10.12	X		Form of Indemnification Agreement (Filed as Exhibit 10.01 to Form 10-Q dated June 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.13	X		

			Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCANA; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.1 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
10.14	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.2 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-00375 (SCE&G)) and incorporated by reference herein)

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10.15	X	X	Three-Year Credit Agreement dated as of October 25, 2012, by and among SCE&G; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and Credit Suisse AG, Cayman Islands Branch and UBS Loan Finance LLC, as Documentation Agents (Filed as Exhibit 99.3 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.16	X	X	Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among Fuel Company; the lenders identified therein; Wells Fargo Bank, National Association, as Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporation Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.4 to Form 8-K on October 30, 2012 (File No. 001-08809 (SCANA); (File No. 001-03375 (SCE&G)) and incorporated by reference herein)
10.17	X		Amended and Restated Five-Year Credit Agreement dated as of October 25, 2012, by and among PSNC Energy; the lenders identified therein; Wells Fargo Bank, National Association, as Issuing Bank, Swingline Lender and Agent; Bank of America, N.A. and Morgan Stanley Senior Funding, Inc., as Co-Syndication Agents; and JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, LTD. and TD Bank N.A., as Documentation Agents (Filed as Exhibit 99.5 to Form 8-K on October 30, 2012 (File No. 001-08809) and incorporated by reference herein)
12.01	X	X	Statement Re Computation of Ratios (Filed herewith)
21.01	X		Subsidiaries of the registrant (Filed herewith under the heading “Corporate Structure and Organization” in Part I, Item I of this Form 10-K and incorporated by reference herein)
23.01	X		Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
23.02		X	Consents of Experts and Counsel (Consent of Independent Registered Public Accounting Firm) (Filed herewith)
24.01	X		Power of Attorney (Filed herewith)
24.02		X	Power of Attorney (Filed herewith)
31.01	X		Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.02	X		Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
31.03		X	Certification of Principal Executive Officer Required by Rule 13a-14 (Filed herewith)
31.04		X	Certification of Principal Financial Officer Required by Rule 13a-14 (Filed herewith)
32.01	X		Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.02	X		Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)

32.03		X	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
32.04		X	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350 (Furnished herewith)
101. INS**	X	X	XBRL Instance Document
101. SCH**	X	X	XBRL Taxonomy Extension Schema
101. CAL**	X	X	XBRL Taxonomy Extension Calculation Linkbase

101. DEF**	X	X	XBRL Taxonomy Extension Definition Linkbase
101. LAB**	X	X	XBRL Taxonomy Extension Label Linkbase
101. PRE**	X	X	XBRL Taxonomy Extension Presentation Linkbase

* Management Contract or Compensatory Plan or Arrangement

** Pursuant to Rule 406T of Regulation S-T, this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.