SCANA CORP
Form 10-Q
August 11, 2014
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
FORM 10-Q

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

For the quarterly period ended June 30, 2014

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

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 ¨ South Carolina Electric & Gas Company Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 ¨ South Carolina Electric & Gas Company Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Registrant	Description of Common Stock	Shares Outstanding at July 31, 2014

SCANA Corporation	Without Par Value	142,052,888
South Carolina Electric & Gas Company	Without Par Value	40,296,147 (a)

(a) Held beneficially and of record by SCANA Corporation.

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

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

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Statements included in this Quarterly Report on Form 10-Q 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 and tax credits, including production tax credits for the New Units;
(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.

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DEFINITIONS

The following abbreviations used in the text 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
BLRA	Base Load Review Act
CA	The designation for a specific pre-fabricated construction module, such as module CA20
CAA	Clean Air Act, as amended
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEO	Chief Executive Officer
CFO	Chief Financial Officer
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.
Court of Appeals	United States Court of Appeals for the District of Columbia
CSAPR	Cross-State Air Pollution Rule
CUT	Customer Usage Tracker
CWA	Clean Water Act
DHEC	South Carolina Department of Health and Environmental Control
DOE	United States Department of Energy
DSM Programs	Demand reduction and energy efficiency programs
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
FERC	United States Federal Energy Regulatory Commission
Fuel Company	South Carolina Fuel Company, Inc.
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse Gas
GWh	Gigawatt hour
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
JEDA	South Carolina Jobs-Economic Development Authority
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
LOC	Lines of Credit

MGP	Manufactured Gas Plant
MMBTU	Million British Thermal Units

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MW	Megawatt
NASDAQ	The NASDAQ Stock Market, Inc.
NCUC	North Carolina Utilities Commission
NEIL	Nuclear Electric Insurance Limited
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
Nuclear Waste Act	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased Gas Adjustment
Price-Anderson	Price-Anderson Indemnification Act
PSNC Energy	Public Service Company of North Carolina, Incorporated
Retail Gas Marketing	SCANA Energy
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
SCPSC	Public Service Commission of South Carolina
SEC	United States Securities and Exchange Commission
SEMI	SCANA Energy Marketing, Inc.
SIP	State Implementation Plan
Summer Station	V. C. Summer Nuclear Station
U. S. Supreme Court	Supreme Court of the United States
VIE	Variable Interest Entity
WNA	Weather Normalization Adjustment

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SCANA CORPORATION
FINANCIAL SECTION

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PART I. FINANCIAL INFORMATION

ITEM 1. F INANCIAL STATEMENTS
SCANA CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2014	December 31, 2013
Assets		
Utility Plant In Service	$12,346	$12,213
Accumulated Depreciation and Amortization	(4,084)	(4,011)
Construction Work in Progress	3,051	2,724
Plant to be Retired, Net	171	177
Nuclear Fuel, Net of Accumulated Amortization	293	310
Goodwill, net of writedown of $230	230	230
Utility Plant, Net	12,007	11,643
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation of $152 and $150	314	317
Assets held in trust, net-nuclear decommissioning	108	101
Other investments	89	86
Nonutility Property and Investments, Net	511	504
Current Assets:		
Cash and cash equivalents	72	136
Receivables, net of allowance for uncollectible accounts of $6 and $6	713	802
Inventories (at average cost):		
Fuel and gas supply	181	232
Materials and supplies	138	131
Prepayments and other	224	120
Total Current Assets	1,328	1,421
Deferred Debits and Other Assets:		
Regulatory assets	1,558	1,360
Pension asset	50	47
Other	172	189
Total Deferred Debits and Other Assets	1,780	1,596
Total	$15,626	$15,164

See Notes to Condensed Consolidated Financial Statements.

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Millions of dollars	June 30, 2014	December 31, 2013
Capitalization and Liabilities		
Common Stock - no par value (shares outstanding: June 30, 2014 - 141.8 million; December 31, 2013 - 140.7 million)	$2,331	$2,280
Retained Earnings	2,585	2,444
Accumulated Other Comprehensive Loss	(62)	(60)
Total Common Equity	4,854	4,664
Long-Term Debt, net	5,681	5,395
Total Capitalization	10,535	10,059
Current Liabilities:		
Short-term borrowings	397	376
Current portion of long-term debt	51	54
Accounts payable	413	425
Customer deposits and customer prepayments	106	88
Taxes accrued	96	206
Interest accrued	84	82
Dividends declared	72	69
Derivative financial instruments	91	8
Other	134	134
Total Current Liabilities	1,444	1,442
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,736	1,703
Deferred investment tax credits	30	32
Asset retirement obligations	589	576
Postretirement benefits	230	227
Regulatory liabilities	853	966
Other	209	159
Total Deferred Credits and Other Liabilities	3,647	3,663
Commitments and Contingencies (Note 9)	—	—
Total	$15,626	$15,164

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars, except per share amounts	2014	2013	2014	2013
Operating Revenues:				
Electric	$610	$610	$1,289	$1,193
Gas - regulated	150	158	608	540
Gas - nonregulated	266	248	719	594
Total Operating Revenues	1,026	1,016	2,616	2,327
Operating Expenses:				
Fuel used in electric generation	211	188	424	374
Purchased power	16	9	41	16
Gas purchased for resale	318	310	987	811
Other operation and maintenance	174	171	354	347
Depreciation and amortization	95	94	190	188
Other taxes	58	55	116	109
Total Operating Expenses	872	827	2,112	1,845
Operating Income	154	189	504	482
Other Income (Expense):				
Other income	69	12	85	25
Other expense	(13)	(10)	(27)	(22)
Interest charges, net of allowance for borrowed funds used during construction of $4, $3, $7 and $5	(76)	(74)	(152)	(148)
Allowance for equity funds used during construction	8	6	14	10
Total Other Expense	(12)	(66)	(80)	(135)
Income Before Income Tax Expense	142	123	424	347
Income Tax Expense	46	38	135	110
Net Income	$96	$85	$289	$237
Per Common Share Data				
Basic Earnings Per Share of Common Stock	$0.68	$0.60	$2.05	$1.73
Diluted Earnings Per Share of Common Stock	$0.68	$0.60	$2.05	$1.72
Weighted Average Common Shares Outstanding (millions)				
Basic	141.7	139.6	141.4	137.0
Diluted	141.7	139.6	141.4	137.9
Dividends Declared Per Share of Common Stock	$0.5250	$0.5075	$1.0500	$1.015

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2014	2013	2014	2013
Net Income	$96	$85	$289	$237
Other Comprehensive Income (Loss), net of tax:				
Unrealized Gains (Losses) on Cash Flow Hedging Activities:				
Unrealized gains (losses) on cash flow hedging activities arising during period, net of tax of $(1), $-, $- and $2	(2)	—	(1)	3
(Gains) losses on cash flow hedging activities reclassified to net income, net of tax of $-, $-, $- and $3	1	1	(1)	5
Amortization of deferred employee benefit plan costs reclassified to net income, net of tax of $-, $-, $- and $-	—	1	—	1
Other Comprehensive Income (Loss)	(1)	2	(2)	9
Total Comprehensive Income	$95	$87	$287	$246

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
Millions of dollars	2014	2013
Cash Flows From Operating Activities:		
Net income	$289	$237
Adjustments to reconcile net income to net cash provided from operating activities:		
Earnings from equity method investments, net of distributions	2	—
Deferred income taxes, net	49	39
Depreciation and amortization	198	194
Amortization of nuclear fuel	20	27
Allowance for equity funds used during construction	(14)	(10)
Carrying cost recovery	(4)	—
Changes in certain assets and liabilities:	—	
Receivables	96	101
Inventories	17	2
Prepayments and other	(107)	(16)
Regulatory liabilities	(131)	56
Accounts payable	(4)	(15)
Taxes accrued	(110)	(63)
Interest accrued	2	—
Pension and other post retirement benefits	(1)	—
Regulatory assets	(166)	9
Other assets	21	(45)
Other liabilities	144	(23)
Net Cash Provided From Operating Activities	301	493
Cash Flows From Investing Activities:		
Property additions and construction expenditures	(517)	(526)
Proceeds from investments (including derivative collateral posted)	101	175
Purchase of investments (including derivative collateral posted)	(120)	(135)
Proceeds from interest rate contract settlement	—	43
Payments upon interest rate contract settlement	(34)	(49)
Net Cash Used For Investing Activities	(570)	(492)
Cash Flows From Financing Activities:		
Proceeds from issuance of common stock	51	247
Proceeds from issuance of long-term debt	294	451
Repayment of long-term debt	(16)	(223)
Dividends	(145)	(137)
Short-term borrowings, net	21	(319)
Net Cash Provided From Financing Activities	205	19
Net Decrease In Cash and Cash Equivalents	(64)	20
Cash and Cash Equivalents, January 1	136	72
Cash and Cash Equivalents, June 30	$72	$92
Supplemental Cash Flow Information:		
Cash paid for– Interest (net of capitalized interest of $7 and $5)	$148	$144
– Income taxes	193	43
Noncash Investing and Financing Activities:		
Accrued construction expenditures	110	90

Capital leases	2	5
Nuclear fuel purchase	—	97

See Notes to Condensed Consolidated Financial Statements.

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SCANA CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
For the Three and Six Months Ended June 30, 2014 and 2013
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in SCANA's Annual Report on Form 10-K for the year ended December 31, 2013. These are interim financial statements and, due to the seasonality of the Company's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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.

Plant to be Retired

As previously disclosed, in 2012 SCE&G identified 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. Three of these units had been retired by December 31, 2013, 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 condensed 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 use and in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

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.

Reconciliations of the weighted average number of common shares for basic and diluted earnings per share computation purposes are as follows:

	Second Quarter		Year to Date	
Millions	2014	2013	2014	2013
Weighted Average Shares Outstanding - Basic	141.7	139.6	141.4	137.0
Effect of dilutive equity forward shares	—	—	—	0.9
Weighted Average Shares - Diluted	141.7	139.6	141.4	137.9

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 41% and 48% of PSNC Energy's natural gas inventory at June 30, 2014 and December 31, 2013, respectively, with a carrying value of $15.8 million and $22.8 million, respectively, through either capacity release or agency relationships. Under the terms of the asset management agreements, PSNC Energy receives storage asset management fees of which 75% are credited to rate payers. No fees are received under supply service agreements. The agreements expire March 31, 2015.

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New Accounting Matter

In May 2014, the Financial Accounting Standards Board issued new accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Company will be required to adopt the new guidance in the first quarter of 2017, and early adoption is not permitted. The Company has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

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 connection with its annual review of base rates for fuel costs, and by order dated April 30, 2013, the SCPSC approved a settlement agreement among SCE&G, the ORS and the SCEUC in which SCE&G agreed to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. The order also provided for the accrual of certain debt-related carrying costs on a portion of SCE&G's under-collected balance of fuel costs, and approved SCE&G's total fuel cost component.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The SCPSC's order also provides for, among other things, the application of approximately $46 million in deferred gains from the late 2013 settlement of certain interest rate swaps, previously recorded as regulatory liabilities, to reduce the under-collected balance of fuel costs in April 2014 and the accrual of certain debt-related carrying costs on its under-collected balance of fuel costs during the period May 1, 2014 through April 30, 2015.

The increase to the base fuel cost component was offset by a reduction in SCE&G’s rate rider related to pension costs, which was approved by the SCPSC in March 2014. The reduction was requested by SCE&G as a result of the lower net periodic benefit cost it expects to record during 2014. See also Note 8.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. By order of the SCPSC, the impact of this action will be considered in future cost of fuel rate adjustments.

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. During the three and six months ended June 30, 2014, $1.4 million and $2.5 million, respectively, 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 deferred income tax 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.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on several 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 retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. Three of these units had been retired by December 31, 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. See also Note 1.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost margin revenue associated with the DSM Programs, along with an incentive for investing in

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such programs. SCE&G submits annual filings regarding the DSM Programs, net lost margin revenues, program costs, incentives and net program benefits. The SCPSC approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated:

Year	Effective	Amount
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million

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

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

- By order dated April 30, 2014, in response to SCE&G's annual DSM Programs filing, the SCPSC approved SCE&G's 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 late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of the net lost margin revenues component of SCE&G's DSM Programs rider, and (3) apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments to the remaining balance of deferred net lost margin revenues as of April 30, 2014, which had been deferred within regulatory assets resulting from the May 2013 order previously described. In addition, the SCPSC, upon recommendation of the ORS, reduced by 25%, or $6.6 million, the amount of net lost margin revenues SCE&G expects to experience over the 12-month period beginning with the first billing cycle of May 2014, and ordered that the $6.6 million be applied to decrease the amount of program costs deferred for recovery. Actual net lost margin revenues not collected in the current DSM Programs rate rider are subject to true up in the following program year.

Electric – BLRA

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 years indicated:

Year	Action		Amount
2013	2.9	% Increase	$67.2 million
2012	2.3	% Increase	$52.1 million

On May 30, 2014, SCE&G filed its annual request for approval of revised rates under the provisions of the BLRA. On July 30, 2014, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its rates in the amount of $66.2 million, or 2.82%. If approved, the revised rates will be effective for bills rendered on and after October 30, 2014.

Gas

SCE&G

The RSA is designed to reduce the volatility of costs charged to customers by allowing for 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 years indicated:

Year	Action		Amount
2013	No change		-
2012	2.1	% Increase	$7.5 million

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On June 13, 2014, SCE&G filed with the SCPSC its quarterly monitoring report for the twelve-month period ended March 31, 2014, and proposed a $3.0 million, or 0.7%, overall decrease to its natural gas rates under the terms of the RSA. The ORS is expected to issue an audit report by September 1, 2014 and the SCPSC is to issue its order by October 15, 2014. If approved, the rate adjustment will be effective for the first billing cycle in November 2014.

SCE&G's natural gas tariffs include a PGA clause 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 review conducted for the 12-month period ended July 31, 2013 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during the review period were reasonable and prudent. The next annual PGA hearing is scheduled for November 6, 2014.

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 changed statutes covering gross receipts, sales and use, excise, franchise and income taxes. On December 6, 2013, 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. On May 13, 2014, the NCUC issued an order requiring utilities to adjust rates to reflect changes in the state corporate income tax rate and to file a proposal to refund amounts collected on a provisional basis. Pursuant to the order, PSNC Energy lowered its rates effective July 1, 2014, and will refund amounts collected on a provisional basis through the normal operation of the Rider D rate mechanism. At June 30, 2014, these amounts were included in customer deposits and customer prepayments on the balance sheet and were not material.

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 regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

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Millions of dollars	June 30, 2014	December 31, 2013
Regulatory Assets:		
Accumulated deferred income taxes	$256	$259
Under-collections - electric fuel adjustment clause	55	18
Environmental remediation costs	41	41
AROs and related funding	375	368
Franchise agreements	28	31
Deferred employee benefit plan costs	232	238
Planned major maintenance	7	—
Deferred losses on interest rate derivatives	284	124
Deferred pollution control costs	36	37
Unrecovered plant	140	145
DSM Programs	50	51
Other	54	48
Total Regulatory Assets	$1,558	$1,360
Regulatory Liabilities:		
Accumulated deferred income taxes	$23	$24
Asset removal costs	713	695
Storm damage reserve	7	27
Monetization of bankruptcy claim	27	29
Deferred gains on interest rate derivatives	83	181
Planned major maintenance	—	10
Total Regulatory Liabilities	$853	$966

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 during annual hearings which are not expected to be recovered in retail electric rates within 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, distribution and other 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 an SCPSC order, SCE&G is recovering these amounts through cost of service rates through 2021.

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, as well as costs deferred pursuant to specific SCPSC regulatory orders. In connection with a 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.

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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 and accrues $18.4 million annually for fossil fueled turbine/generation equipment maintenance, and collects and accrues $17.2 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 made or 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 over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC. Also, in 2014, as discussed at Rate Matters - Electric - Cost of Fuel and Rate Matters - Electric - Base Rates, certain of these deferred amounts were applied to offset under-collected fuel balances and unrecorded net lost margin revenues related to DSM Programs.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

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 through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs at SCE&G. As a result of an April 2014 SCPSC order, deferred costs are currently being recovered over approximately ten years through a SCPSC approved rider. See Rate Matters - Electric - Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 33 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of 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. In 2014, $15.5 million of the reserve was applied to offset incremental storm damage costs. Also, as discussed at Rate Matters - Electric - Base Rates, in April 2014 $5.0 million of the reserve was applied to offset unrecovered net lost margin revenues related to DSM Programs.

The monetization of bankruptcy claim represents proceeds from the sale of a bankruptcy claim which are being 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 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.

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3.COMMON EQUITY

Changes in common equity during the six months ended June 30, 2014 and 2013 were as follows:

Millions of dollars	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss): Gains (Losses) on Cash Flow Hedges	Deferred Employee Benefit Plans	Total AOCI	Total Common Equity
Balance as of January 1, 2014	$2,280	$2,444	$(52)	$(8)	$(60)	$4,664
Net Income		289				289
Other Comprehensive Loss		—	(2)	—	(2)	(2)
Total Comprehensive Income (Loss)		289	(2)	—	(2)	287
Issuance of Common Stock	51					51
Dividends Declared		(148)				(148)
Balance as of June 30, 2014	$2,331	$2,585	$(54)	$(8)	$(62)	$4,854
Balance as of January 1, 2013	$1,983	$2,257	$(70)	$(16)	$(86)	$4,154
Net Income		237				237
Other Comprehensive Income		—	9	—	9	9
Total Comprehensive Income		237	9	—	9	246
Issuance of Common Stock	247					247
Dividends Declared		(141)				(141)
Balance as of June 30, 2013	$2,230	$2,353	$(61)	$(16)	$(77)	$4,506

SCANA had 200 million shares of common stock authorized as of June 30, 2014 and December 31, 2013, of which 141.8 million and 140.7 million were issued and outstanding at June 30, 2014 and December 31, 2013, respectively.

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 $196.2 million.

For information related to the reclassifications from AOCI, see Note 6.

4.LONG-TERM DEBT AND LIQUIDITY

Long-term Debt

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale 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 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 at a premium, for the benefit of SCE&G, $39.5 million of 4.00% 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.

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

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Liquidity

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	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013	June 30, 2014	December 31, 2013
Lines of credit:						
Total committed long-term	$300	$300	$1,400	$1,400	$100	$ 100
Outstanding commercial paper (270 or fewer days)	$81	$125	$316	$251	—	—
Weighted average interest rate	0.37 %	0.39 %	0.27 %	0.27 %	—	—
Letters of credit supported by LOC	$3	$3	$0.3	$0.3	—	—
Available	$216	$172	$1,084	$1,149	$100	$ 100

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 a party to a three-year credit agreement in the amount of $200 million. 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 $1,800 million credit facilities, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A., Credit Suisse AG, Cayman Island 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.

5.INCOME TAXES

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 $3.0 million. During 2014 the Company amended additional tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, the Company increased its unrecognized tax benefit by $6.7 million (for a total of $9.7 million). If recognized, this tax benefit would affect the Company’s effective tax rate. No other material changes in the status of the Company’s tax positions have occurred through June 30, 2014.

The Company recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. Because no refunds related to the unrecognized tax benefits have yet been received, the Company has not recorded any interest expense or penalties associated with them.

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.

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6.DERIVATIVE FINANCIAL INSTRUMENTS

The Company recognizes all derivative instruments as either assets or liabilities in the statement 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 condensed consolidated statements of cash flows.

PSNC Energy hedges natural gas purchasing activities using over-the-counter options and NYMEX futures and options. PSNC Energy's tariffs 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 under- or over-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.

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Pursuant to regulatory orders, 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, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination 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 June 30, 2014				
Commodity contracts	4,060,000	7,279,000	2,372,000	13,711,000
Energy management contracts (a)	—	—	25,139,515	25,139,515
Total (a)	4,060,000	7,279,000	27,511,515	38,850,515
As of December 31, 2013				
Commodity contracts	6,070,000	6,726,000	2,560,000	15,356,000
Energy management contracts (b)	—	—	27,359,958	27,359,958
Total (b)	6,070,000	6,726,000	29,919,958	42,715,958

(a) Includes an aggregate 219,928 MMBTU related to basis swap contracts in Energy Marketing.
(b) Includes an aggregate 348,453 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 $124.4 million at June 30, 2014 and $128.8 million at December 31, 2013. The Company was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.1 billion at June 30, 2014 and $1.3 billion at December 31, 2013.

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The fair value of energy-related derivatives and interest rate derivatives was reflected in the condensed 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 June 30, 2014				
Derivatives designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$5
			Other deferred credits and other liabilities	21
Commodity contracts	Prepayments and other	$1	Derivative financial instruments	1
Total		$1		$27
Derivatives not designated as hedging instruments				
Interest rate contracts	Other deferred debits and other assets	$2	Derivative financial instruments	$82
			Other deferred credits and other liabilities	38
Commodity contracts	Prepayments and other	2		
Energy management contracts	Prepayments and other	3	Derivative financial instruments	3
	Other deferred debits and other assets	3	Other deferred credits and other liabilities	3
Total		$10		$126
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$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	Derivative financial instruments	$1
	Other deferred debits and other assets	19		
Commodity contracts	Prepayments and other	2		
Energy management contracts	Prepayments and other	4	Derivative financial instruments	4
	Other deferred debits and other assets	4	Other deferred credits and other liabilities	4

Total	$42	$9

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

Fair Value Hedges

The Company had no interest rate or commodity derivatives designated as fair value hedges for any period presented.

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Cash Flow Hedges

Derivatives in Cash Flow Hedging Relationships

Millions of dollars	Gain (Loss) Deferred in Regulatory Accounts (Effective Portion) 2014	2013	Location	Loss Reclassified from Deferred Accounts into Income (Effective Portion) 2014	2013
Three Months Ended June 30,					
Interest rate contracts	$(1)	$61	Interest expense	—	—
Six Months Ended June 30,					
Interest rate contracts	$(4)	$96	Interest expense	$(1)	$(1)

Millions of dollars	Gain (Loss) Recognized in OCI, net of tax (Effective Portion) 2014	2013	Location	Gain (Loss) Reclassified from AOCI into Income, net of tax (Effective Portion) 2014	2013
Three Months Ended June 30,					
Interest rate contracts	$(2)	$3	Interest expense	$(2)	$(1)
Commodity contracts	—	(3)	Gas purchased for resale	1	—
Total	$(2)	$—		$(1)	$(1)
Six Months Ended June 30,					
Interest rate contracts	$(4)	$4	Interest expense	$(4)	$(3)
Commodity contracts	3	(1)	Gas purchased for resale	5	(2)
Total	$(1)	$3		$1	$(5)

As of June 30, 2014, the Company expects that during the next 12 months reclassifications from AOCI to earnings arising from cash flow hedges will include an insignificant decrease to gas cost and approximately $7.1 million as an increase to interest expense, assuming natural gas and financial markets remain at their current levels. As of June 30, 2014, 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 each of the three and six months ended June 30, 2014 and 2013, respectively.

Derivatives not designated as Hedging Instruments

Millions of dollars	Loss Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income Location	Amount
Three Months Ended June 30, 2014			
Interest rate contracts	$(73)	Other income	$55
Six Months Ended June 30, 2014			
Interest rate contracts	$(185)	Other income	$55

For the three and six months ended June 30, 2013, no losses were deferred in regulatory accounts, and no amounts were reclassified from deferred accounts into income. As of June 30, 2014, the Company expects that during the next 12 months reclassifications from other current liabilities and deferred regulatory accounts to earnings arising from derivatives not designated as hedges will include $14.1 million as an increase to other income. The effect of this increase on net income will be entirely offset by net lost margin revenues from DSM Programs as further described in Note 2.

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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 may 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 permit the secured party to demand the posting of 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 may require the Company to provide collateral upon the occurrence of specific events, primarily credit downgrades. As of June 30, 2014 and December 31, 2013, the Company has posted $44.4 million and $26.8 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 condensed consolidated balance sheets. Collateral related to noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the condensed consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2014 and December 31, 2013, the Company could have been required to post an additional $104.5 million and $- million, respectively, of collateral with its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of June 30, 2014 and December 31, 2013 is $148.9 million and $25.2 million, respectively.

In addition, as of June 30, 2014 and December 31, 2013, 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 were fully triggered as of June 30, 2014 and December 31, 2013, the Company could request $1.0 million and $34.1 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 June 30, 2014 and December 31, 2013 is $1.0 million and $34.1 million, respectively. In addition, at June 30, 2014, the Company could have called on letters of credit in the amount of $4.0 million related to $6.0 million in commodity derivatives that are in a net asset position, compared to letters of credit of $6.0 million related to derivatives of $6.0 million at December 31, 2013, if all the contingent features underlying these instruments had been fully triggered.

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

				Gross Amounts Not Offset in the Statement of Financial Position		
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	Financial Instruments	Cash Collateral Received	Net Amount
As of June 30, 2014						
Interest rate contracts	$2	—	$2	$(2)	—	—
Commodity contracts	3	—	3	—	—	$3

Energy management contracts	6	—	6	—	—	6
Total	$11	—	$11	$(2)	—	$9

Balance sheet location	Prepayments and other	$6
	Other deferred debits and other assets	5
	Total	$11

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As of December 31, 2013						
Interest rate contracts	$32	—	$32	$(1)	—	$31
Commodity contracts	4	—	4	—	—	4
Energy management contracts	8	—	8	—	—	8
Total	$44	—	$44	$(1)	—	$43

Balance sheet location	Prepayments and other	$21
	Other deferred debits and other assets	23
	Total	$44

Information related to the Company's offsetting of 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 June 30, 2014						
Interest rate contracts	$146	—	$146	$(2)	$(39)	$105
Commodity contracts	1	—	1	—	—	1
Energy management contracts	6	—	6	—	(5)	1
	$153	—	$153	$(2)	$(44)	$107
Balance sheet location	Derivative financial instruments		$90			
	Other deferred credits and other liabilities		63			
	Total		$153			
As of December 31, 2013						
Interest rate contracts	$20	—	$20	$(1)	$(19)	—
Energy management contracts	8	—	8	—	(6)	$2
	$28	—	$28	$(1)	$(25)	$2
Balance sheet location	Derivative financial instruments		$10			
	Other deferred credits and other liabilities		18			
	Total		$28			

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:

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	As of June 30, 2014		As of December 31, 2013	
Millions of dollars	Level 1	Level 2	Level 1	Level 2
Assets:				
Available for sale securities	$12	—	$9	—
Interest rate contracts	—	$2	—	$32
Commodity contracts	2	1	2	2
Energy management contracts	1	5	1	7
Liabilities:				
Interest rate contracts	—	146	—	20
Commodity contracts	—	1	—	—
Energy management contracts	—	9	—	12

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 June 30, 2014 and December 31, 2013 were as follows:

	June 30, 2014		December 31, 2013	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$5,732.4	$6,513.0	$5,449.3	$5,916.3

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 fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS

Pension and Other Postretirement Benefit Plans

Components of net periodic benefit cost recorded by the Company were as follows:

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2014	2013	2014	2013
Three months ended June 30,				
Service cost	$5.0	$5.9	$1.3	$1.6
Interest cost	10.2	9.4	3.1	2.7
Expected return on assets	(16.8)	(15.3)	—	—
Prior service cost amortization	1.0	1.7	0.1	0.2
Transition obligation amortization	—	—	—	0.1
Amortization of actuarial losses	1.3	5.5	0.1	0.9
Net periodic benefit cost	$0.7	$7.2	$4.6	$5.5

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	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2014	2013	2014	2013
Six months ended June 30,				
Service cost	$10.0	$11.8	$2.5	$3.2
Interest cost	20.4	18.9	6.2	5.5
Expected return on assets	(33.6)	(30.7)	—	—
Prior service cost amortization	2.0	3.4	0.2	0.4
Transition obligation amortization	—	—	—	0.3
Amortization of actuarial losses	2.6	10.9	0.2	1.7
Net periodic benefit cost	$1.4	$14.3	$9.1	$11.1

No significant contribution to the pension trust is expected for the foreseeable future, nor is a limitation on benefit payments expected to apply. SCE&G recovers current pension costs through either a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations. Certain pension costs arising prior to 2013 were deferred for future recovery under regulatory orders as discussed in Note 2.

9. 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 SCE&G'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 premium, SCE&G’s portion of the retrospective premium assessment would not exceed $43.5 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's 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. As of June 30, 2014, SCE&G's 55% share of the estimated cash outlays (future value, excluding AFC) totaled approximately $5.3 billion for plant and related transmission infrastructure costs, and was projected based on historical one-year and five-year escalation rates as required by the SCPSC.

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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 from Santee Cooper. 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. As of June 30, 2014, and based on the updated construction milestone schedule and capital costs schedule approved by the SCPSC in November 2012 (see below), SCE&G estimated such cost 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 for the additional ownership interest would be reflected in a revised rates filing under the BLRA.

Under the BLRA, the SCPSC has approved, among other things, the construction milestone schedule and capital costs estimates schedule for the New Units. The effect of this approval is that it constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved construction milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. The BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2.

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 have impacted the project budget and schedule. SCE&G expects to resolve all disputes through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

In November 2012, the SCPSC approved a petition by SCE&G under the BLRA for an updated construction milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC 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 known claims by the Consortium 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. Immediately thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its order, and 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, contending that the SCPSC erred in granting approval of the updated capital costs for the New Units. The South Carolina Supreme Court heard arguments related to those appeals on April 16, 2014. SCE&G is unable to predict the outcome of these appeals.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC has also approved an 18-month contingency period beyond each of these dates.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain 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, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. 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 Unit 2 during the first half of 2015.

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 schedules 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, construction work crew efficiencies, and other items. The result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014 SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 is expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later. These expected substantial completion dates do not reflect all efforts that may be possible to mitigate delay nor has SCE&G accepted this new schedule. The Consortium has not yet provided any cost estimates related to the delay. SCE&G anticipates that the revised schedule and the cost estimate at completion will be finalized in the latter half of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of that new schedule when it is finalized.

SCE&G cannot predict with certainty the extent to which the delays in the substantial completion of the New Units will result in increased project costs. SCE&G has not accepted responsibility for any delay-related costs and expects to have 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 facility, which will also be included in discussions with the Consortium.

The construction milestone schedule approved by the SCPSC in November 2012 provides for 146 construction milestone dates, which are each subject to an 18-month schedule contingency. As of August 4, 2014, 100 milestones have been completed. Based on the preliminary schedule information arising from the re-baselining effort, the completion dates for a number of the remaining milestones are expected to extend beyond the 18-month contingency periods. As a result, upon completion of the re-baselining and the finalization of the revised schedule and cost estimate at completion, SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA construction milestone schedule and/or capital costs estimates schedule. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

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 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 each of the New Units (advanced nuclear units, as defined), to the extent that such Unit is operational before January 1, 2021, 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 Unit 2 and November 2013 for Unit 3), 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 can 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 foreseeable future.

The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units. On June 2, 2014, the EPA released the Clean Power Plan proposed to regulate carbon dioxide emissions from existing units. The proposed rule includes state specific rate-based goals for carbon dioxide emissions, as well as guidelines for states to follow in developing SIPs to achieve those goals. The Company is evaluating the proposed rule which may be revised before it becomes final in June, 2015. As currently proposed, states will have from one to three years from the date of any final rule to issue SIPs that will ultimately define the specific compliance methodology that will be applied to existing units in that state. The Company expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

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

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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 Court of Appeals 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. On April 29, 2014, the U. S. Supreme Court reversed the judgment of the Court of Appeals, and CSAPR was remanded to the Court of Appeals for further proceedings consistent with the U. S. Supreme Court opinion. On June 26, 2014, the EPA filed a motion with the Court of Appeals to lift the stay of the CSAPR. While the motion is being considered, CAIR remains in place and no immediate action from states or affected sources is expected. 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 September 30, 2015. The EPA expects compliance within a three to six year time frame as NPDES permits are renewed.

On May 19, 2014, the EPA finalized a rule that modifies requirements for existing cooling water intake structures. The rule becomes effective 60 days after publication in the Federal Register. 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 and subsequent obligation via consent decree, the EPA committed to issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 19, 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 June 30, 2014, 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 is constructing 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. See also Note 2.

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.

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SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of byproduct 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 million, which is accrued in Other within Deferred Credits and Other Liabilities on the condensed consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At June 30, 2014, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.4 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 potentially responsible parties. PSNC Energy has recorded a liability and associated regulatory asset of approximately $2.5 million, the estimated remaining liability at June 30, 2014. PSNC Energy expects to recover through rates any cost allocable to PSNC Energy arising from the remediation of these sites.

10. SEGMENT OF BUSINESS INFORMATION

The Company's reportable segments are listed in the following table. The Company uses operating income to measure profitability for its regulated operations; therefore, net income is not allocated to the Electric Operations and Gas Distribution segments. The Company uses net income to measure profitability for its Retail Gas Marketing and Energy Marketing segments. Gas Distribution is comprised of the local distribution operations of SCE&G and PSNC Energy which meet the criteria for aggregation. All Other includes equity method investments and other nonreportable segments. Nonreportable segments include a FERC-regulated interstate pipeline company and other companies that conduct nonregulated operations in energy-related and telecommunications industries.

Millions of dollars	External Revenue	Intersegment Revenue	Operating Income	Net Income
Three Months Ended June 30, 2014				
Electric Operations	$610	$2	$143	n/a
Gas Distribution	146	—	7	n/a
Retail Gas Marketing	79	—	n/a	$(3)
Energy Marketing	187	54	n/a	—
All Other	9	104	6	(2)
Adjustments/Eliminations	(5)	(160)	(2)	101
Consolidated Total	$1,026	$—	$154	$96
Six Months Ended June 30, 2014				
Electric Operations	$1,289	$4	$341	n/a
Gas Distribution	601	—	104	n/a
Retail Gas Marketing	299	—	n/a	$19
Energy Marketing	420	107	n/a	7
All Other	18	214	14	2
Adjustments/Eliminations	(11)	(325)	45	261
Consolidated Total	$2,616	$—	$504	$289
Three Months Ended June 30, 2013				
Electric Operations	$610	$2	$178	n/a
Gas Distribution	155	—	7	n/a
Retail Gas Marketing	79	—	n/a	$(3)

Energy Marketing	169	47	n/a	1
All Other	7	101	6	(2)
Adjustments/Eliminations	(4)	(150)	(2)	89
Consolidated Total	$1,016	$—	$189	$85

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Six Months Ended June 30, 2013				
Electric Operations	$1,193	$4	$331	n/a
Gas Distribution	534	—	100	n/a
Retail Gas Marketing	258	—	n/a	$19
Energy Marketing	336	89	n/a	4
All Other	19	208	13	1
Adjustments/Eliminations	(13)	(301)	38	213
Consolidated Total	$2,327	$—	$482	$237

Segment Assets	June 30, 2014	December 31, 2013
Electric Operations	$9,723	$9,488
Gas Distribution	2,372	2,340
Retail Gas Marketing	122	172
Energy Marketing	129	133
All Other	1,385	1,378
Adjustments/Eliminations	1,895	1,653
Consolidated Total	$15,626	$15,164

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SCANA CORPORATION

The following discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in SCANA's Annual Report on Form 10-K for the year ended December 31, 2013.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014
AS COMPARED TO THE CORRESPONDING PERIODS IN 2013

Earnings Per Share

Earnings per share was as follows:

	Second Quarter		Year to Date	
	2014	2013	2014	2013
Basic earnings per share	$0.68	$0.60	$2.05	$1.73
Diluted earnings per share	$0.68	$0.60	$2.05	$1.72

Second Quarter

Basic earnings per share increased primarily due to the effects of weather and base rate increases under the BLRA. These increases were partially offset by higher operation and maintenance expenses, higher property taxes, higher interest cost and dilution from additional shares outstanding, as further discussed below.

Year to Date

Basic earnings per share increased due to higher electric and gas margins and other income. These increases were partially offset by higher operation and maintenance expenses, higher property taxes, higher depreciation expense, higher interest cost and dilution from additional shares outstanding.

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

Dividends Declared

SCANA's Board of Directors has declared the following dividends on common stock during 2014:

Declaration Date	Dividend Per Share	Record Date	Payment Date
February 20, 2014	$0.5250	March 10, 2014	April 1, 2014
April 24, 2014	$0.5250	June 10, 2014	July 1, 2014
July 31, 2014	$0.5250	September 10, 2014	October 1, 2014

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:

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	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Operating revenues	$612.4	0.1 %	$611.6	$1,292.3	7.9 %	$1,197.2
Less: Fuel used in generation	212.7	12.4 %	189.2	426.5	13.2 %	376.9
Purchased power	16.3	85.2 %	8.8	41.3	*	15.8
Margin	$383.4	(7.3)%	$413.6	$824.5	2.5 %	$804.5

* Greater than 100%

Second Quarter

Pursuant to orders of the SCPSC, electric margin was adjusted downward by $60.1 million related to fuel cost recovery and SCE&G's DSM Programs. These adjustments are fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G's storm damage reserve, both of which had been deferred in regulatory accounts. The electric margin decrease was partially offset by the effects of weather of $13.4 million, base rate increases under the BLRA of $12.2 million and customer growth of $3.8 million.

Year to Date

Electric margin increased due to the effects of weather of $33.5 million, base rate increases under the BLRA of $24.8 million and customer growth of $7.7 million. These margin increases were partially offset by the $60.1 million downward adjustment to electric revenues pursuant to the SCPSC orders previously discussed.

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

	Second Quarter			Year to Date		
Classification	2014	Change	2013	2014	Change	2013
Residential	1,904	6.7 %	1,784	4,055	11.3 %	3,642
Commercial	1,825	2.7 %	1,777	3,575	3.7 %	3,446
Industrial	1,542	1.6 %	1,518	2,994	2.5 %	2,921
Other	149	3.5 %	144	290	3.9 %	279
Total Retail Sales	5,420	3.8 %	5,223	10,914	6.1 %	10,288
Wholesale	235	3.1 %	228	479	(2.4)%	491
Total Sales	5,655	3.7 %	5,451	11,393	5.7 %	10,779

Second Quarter

Retail sales volume increased primarily due to the effects of weather and customer growth.

Year to Date

Retail sales volume increased primarily due to the effects of weather and customer growth. The decrease in wholesale sales is primarily due to the expiration of a customer contract.

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:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013

Operating revenues	$146.4	(5.4	)%	$154.7	$601.6	12.7	%	$534.0
Less: Gas purchased for resale	75.6	(11.6	)%	85.5	368.1	19.4	%	308.2
Margin	$70.8	2.3	%	$69.2	$233.5	3.4	%	$225.8

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Second Quarter

Margin increased primarily due to residential and commercial customer growth. SCE&G's WNA and PSNC Energy's CUT mitigate weather-related fluctuations in margin but have no impact on volumes.

Year to Date

Margin increased primarily due to residential and commercial customer growth of $5.0 million and increased average usage at SCE&G of $2.4 million.

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

	Second Quarter			Year to Date		
Classification (in thousands)	2014	Change	2013	2014	Change	2013
Residential	3,035	(21.5)%	3,866	29,015	15.0 %	25,240
Commercial	4,645	(4.9)%	4,886	17,412	11.3 %	15,644
Industrial	5,046	(7.2)%	5,438	10,379	(10.5)%	11,599
Transportation	11,465	17.1 %	9,787	21,571	2.8 %	20,988
Total	24,191	0.9 %	23,977	78,377	6.7 %	73,471

Second Quarter

Residential and commercial sales volumes decreased primarily due to the effects of weather. Industrial sales volumes decreased due to a customer switching to an alternative fuel source. Transportation sales volume increased primarily from natural gas-fired generation.

Year to Date

Residential and commercial sales volumes increased primarily due to the effects of weather. Industrial sales volumes decreased due to weather related curtailments and a customer switching to an alternative fuel source.

Retail Gas Marketing

Retail Gas Marketing is comprised of SCANA Energy, which operates in Georgia’s natural gas market. Retail Gas Marketing operating revenues and net income (loss) were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Operating revenues	$78.9	(0.4)%	$79.2	$299.0	15.8 %	$258.2
Net income (loss)	(3.1)	14.8 %	(2.7)	19.2	(1.0)%	19.4

Second Quarter and Year to Date

Operating revenues increased in 2014 due to the increased demand related to winter weather and customer growth. Net income in 2014 was impacted by higher revenues related to the colder than normal weather, offset by higher costs including commodity costs and bad debt expense.

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Energy Marketing

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

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Operating revenues	$240.5	11.1 %	$216.4	$527.3	23.9 %	$425.5
Net income	1.1	10.0 %	1.0	7.7	*	3.7

* Greater than 100%

Second Quarter and Year to Date

Operating revenues and net income increased due to higher market prices and margins on incremental sales.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Other operation and maintenance	$174.5	2.2 %	$170.8	$353.7	2.0 %	$346.9
Depreciation and amortization	95.3	0.8 %	94.5	190.2	1.3 %	187.8
Other taxes	57.9	6.2 %	54.5	115.6	5.8 %	109.3

Second Quarter

Other operation and maintenance expenses increased primarily due to higher labor expenses, including incentive compensation. Depreciation and amortization expense increased due to net plant additions. Other taxes increased primarily due to higher property taxes.

Year to Date

Other operation and maintenance expenses increased primarily due to higher labor expenses, including incentive compensation, of $1.3 million, and storm expenses of $1.8 million. Depreciation and amortization expense increased due to net plant additions. Other taxes increased primarily due to higher property taxes.

Other Income (Expense)

Other income (expense) includes the results of certain incidental (non-utility) activities, the activities of certain non-regulated subsidiaries and 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), both of which have the effect of increasing reported net income. Other income increased primarily due to the recognition of $55.1 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

Interest Expense

Interest charges increased primarily due to increased borrowings.

Income Taxes

Income taxes for the three and six months ended June 30, 2014 were higher than the same periods in 2013 primarily due to higher income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

The Company anticipates that its 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 six and 12 months ended June 30, 2014 was 3.65 and 3.41, respectively.

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. These letters of credit expire, subject to renewal, in the fourth quarter of 2014.

At June 30, 2014, the Company had net available liquidity of approximately $1.5 billion, comprised of cash on hand and available amounts under lines of credit. The credit agreements total an aggregate of $1.8 billion, of which $200 million is scheduled to expire in October 2016 and the remainder is scheduled to expire in October 2018. The Company regularly monitors the commercial paper and short-term credit markets to optimize the timing of repayment of outstanding balances on its draws, if any, from the credit facilities. The Company's long-term debt portfolio has a weighted average maturity of approximately 19 years and bears an average interest cost of 5.7%. Substantially all of the 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.

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 and is expected to be renewed.

SCANA issued approximately $52 million of common stock during the six months ended June 30, 2014 through various compensation and dividend reinvestment plans. Similar issuances are expected in future periods. 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 million.

SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2014 through 2016, which are subject to continuing review and adjustment, are $805 million in 2014, $930 million in 2015, and $696 million in 2016.

OTHER MATTERS

In June 2014, the Distributed Energy Resource Act became law in South Carolina. Among other things, this law (i) authorizes SCE&G, at its discretion, to implement a distributed energy resource program and recover the reasonable and prudent costs incurred in implementing such a program, (ii) permits non-utilities and utilities to lease renewable electric generation facilities to homeowners and businesses, and (iii) requires the SCPSC to establish a net energy metering rate methodology. SCE&G is actively participating, along with numerous other stakeholders, in the SCPSC's net energy metering proceeding, which is expected to continue into 2015. As for implementing a distributed energy program, SCE&G is evaluating its options under the law.

For information related to environmental matters, nuclear generation, and claims and litigation, see Note 9 to the condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk - The Company's market risk exposures relative to interest rate risk have not changed materially compared with the Company's Annual Report on Form 10-K for the year ended December 31, 2013. Interest rates on substantially all of the Company's outstanding long-term debt, other than credit facility draws, are fixed either through the

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issuance of fixed rate debt or through the use of interest rate derivatives. The Company is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near future.

For further discussion of changes in long-term debt and interest rate derivatives, see ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – LIQUIDITY AND CAPITAL RESOURCES and also Notes 4, 6 and 7 of the condensed consolidated financial statements.

Commodity price risk - The Company uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. See Note 6 and 7 of the condensed consolidated financial statements. 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 for these or similar instruments.

	Expected Maturity			Expected Maturity	
Futures - Long	2014	2015	Options Purchased Call - Long	2014	2015
Settlement Price (a)	4.47	4.44	Strike Price (a)	4.04	4.62
Contract Amount (b)	5.1	2.3	Contract Amount (b)	8.5	9.1
Fair Value (b)	5.6	2.4	Fair Value (b)	1.1	0.7

Futures - Short	2014	2015
Settlement Price (a)	4.45	4.10
Contract Amount (b)	0.5	0.3
Fair Value (b)	0.5	0.3

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

	Expected Maturity				
Swaps	2014	2015	2016	2017	2018
Commodity Swaps:					
Pay fixed/receive variable (b)	30.6	39.5	13.2	4.6	3.6
Average pay rate (a)	4.4994	4.6883	4.5863	4.2167	4.2421
Average received rate (a)	4.4764	4.3443	4.2474	4.3941	4.5803
Fair value (b)	30.5	36.6	12.2	4.7	3.8
Pay variable/receive fixed (b)	14.7	19.3	11.7	4.7	3.8
Average pay rate (a)	4.4648	4.2486	4.2441	4.3941	4.5803
Average received rate (a)	4.4540	4.7742	4.5957	4.2217	4.2471
Fair value (b)	14.6	21.7	12.7	4.6	3.6
Basis Swaps:					
Pay variable/receive variable (b)	0.5	0.5	—	—	—
Average pay rate (a)	4.5125	4.5802	—	—	—
Average received rate (a)	4.4727	4.5587	—	—	—
Fair value (b)	0.5	0.5	—	—	—

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

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ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2014, SCANA conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of (a) the effectiveness of the design and operation of its disclosure controls and procedures and (b) any change in its internal control over financial reporting. Based on this evaluation, the CEO and CFO concluded that, as of June 30, 2014, SCANA's disclosure controls and procedures were effective. There has been no change in SCANA's internal control over financial reporting during the quarter ended June 30, 2014 that has materially affected or is reasonably likely to materially affect SCANA's internal control over financial reporting.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
FINANCIAL SECTION

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ITEM 1. FINANCIAL STATEMENTS
SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

Millions of dollars	June 30, 2014	December 31, 2013
Assets		
Utility Plant In Service	$10,486	$10,378
Accumulated Depreciation and Amortization	(3,558)	(3,499)
Construction Work in Progress	2,977	2,682
Plant to be Retired, Net	171	177
Nuclear Fuel, Net of Accumulated Amortization	293	310
Utility Plant, Net ($700 and $720 related to VIEs)	10,369	10,048
Nonutility Property and Investments:		
Nonutility property, net of accumulated depreciation	69	69
Assets held in trust, net-nuclear decommissioning	108	101
Other investments	3	3
Nonutility Property and Investments, Net	180	173
Current Assets:		
Cash and cash equivalents	43	92
Receivables, net of allowance for uncollectible accounts of $4 and $3	506	486
Affiliated receivables	28	19
Inventories (at average cost):		
Fuel and gas supply	106	132
Materials and supplies	126	120
Prepayments and other	117	80
Total Current Assets ($99 and $147 related to VIEs)	926	929
Deferred Debits and Other Assets:		
Pension asset	100	96
Regulatory assets	1,499	1,303
Other	135	151
Total Deferred Debits and Other Assets ($57 and $35 related to VIEs)	1,734	1,550
Total	$13,209	$12,700

See Notes to Condensed Consolidated Financial Statements.

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Millions of dollars	June 30, 2014	December 31, 2013
Capitalization and Liabilities		
Common Stock - no par value, 40.3 million shares outstanding for all periods presented	$2,534	$2,479
Retained Earnings	1,990	1,896
Accumulated Other Comprehensive Loss	(3)	(3)
Total Common Equity	4,521	4,372
Noncontrolling Interest	120	117
Total Equity	4,641	4,489
Long-Term Debt, net	4,298	4,007
Total Capitalization	8,939	8,496
Current Liabilities:		
Short-term borrowings	316	251
Current portion of long-term debt	45	48
Accounts payable	251	241
Affiliated payables	173	117
Customer deposits and customer prepayments	58	56
Taxes accrued	87	223
Interest accrued	65	64
Dividends declared	64	62
Derivative financial instruments	83	1
Other	90	71
Total Current Liabilities	1,232	1,134
Deferred Credits and Other Liabilities:		
Deferred income taxes, net	1,538	1,509
Deferred investment tax credits	30	32
Asset retirement obligations	559	547
Postretirement benefits	175	173
Regulatory liabilities	613	732
Other	123	77
Total Deferred Credits and Other Liabilities	3,038	3,070
Commitments and Contingencies (Note 9)	—	—
Total	$13,209	$12,700

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2014	2013	2014	2013
Operating Revenues:				
Electric	$612	$612	$1,292	$1,197
Gas	86	84	265	227
Total Operating Revenues	698	696	1,557	1,424
Operating Expenses:				
Fuel used in electric generation	213	189	427	377
Purchased power	16	9	41	16
Gas purchased for resale	55	54	165	131
Other operation and maintenance	138	135	279	274
Depreciation and amortization	79	79	157	156
Other taxes	52	50	105	99
Total Operating Expenses	553	516	1,174	1,053
Operating Income	145	180	383	371
Other Revenue (Expense):				
Other revenue	59	—	62	—
Other expense	(7)	(4)	(13)	(7)
Interest charges, net of allowance for borrowed funds used during construction of $4, $3, $7 and $5	(56)	(54)	(112)	(108)
Allowance for equity funds used during construction	7	6	13	9
Total Other Revenue (Expense)	3	(52)	(50)	(106)
Income Before Income Tax Expense	148	128	333	265
Income Tax Expense	49	40	108	85
Net Income	99	88	225	180
Net Income Attributable to Noncontrolling Interest	(3)	(3)	(6)	(6)
Earnings Available to Common Shareholder	$96	$85	$219	$174
Dividends Declared on Common Stock	$64	$64	$128	$128

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
Millions of dollars	2014	2013	2014	2013
Net Income	$99	$88	$225	$180
Total Comprehensive Income	99	88	225	180
Comprehensive income attributable to noncontrolling interest	(3)	(3)	(6)	(6)
Comprehensive income available to common shareholder	$96	$85	$219	$174

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
Millions of dollars	2014	2013
Cash Flows From Operating Activities:		
Net income	$225	$180
Adjustments to reconcile net income to net cash provided from operating activities:		
Losses from equity method investments	3	1
Deferred income taxes, net	29	26
Depreciation and amortization	157	156
Amortization of nuclear fuel	20	27
Allowance for equity funds used during construction	(13)	(9)
Carrying cost recovery	(4)	—
Changes in certain assets and liabilities:		
Receivables	(22)	(12)
Inventories	(2)	(4)
Prepayments and other	(24)	(45)
Pension and other post retirement benefits	(3)	—
Regulatory assets	(164)	9
Regulatory liabilities	(129)	58
Accounts payable	20	(4)
Taxes accrued	(136)	(38)
Interest accrued	1	1
Other assets	7	(31)
Other liabilities	163	(12)
Net Cash Provided From Operating Activities	128	303
Cash Flows From Investing Activities:		
Property additions and construction expenditures	(452)	(478)
Proceeds from investments (including derivative collateral posted)	75	132
Purchase of investments (including derivative collateral posted)	(94)	(104)
Proceeds from interest rate contract settlement	—	43
Payments upon interest rate contract settlement	(34)	(49)
Net Cash Used For Investing Activities	(505)	(456)
Cash Flows From Financing Activities:		
Proceeds from issuance of long-term debt	294	451
Repayment of long-term debt	(11)	(218)
Dividends	(126)	(110)
Contributions from parent	55	255
Short-term borrowings –affiliate, net	51	(15)
Short-term borrowings, net	65	(211)
Net Cash Provided From Financing Activities	328	152
Net Decrease In Cash and Cash Equivalents	(49)	(1)
Cash and Cash Equivalents, January 1	92	51
Cash and Cash Equivalents, June 30	$43	$50
Supplemental Cash Flow Information:		
Cash paid for– Interest (net of capitalized interest of $7 and $5)	$102	$99

– Income taxes	127	24
Noncash Investing and Financing Activities:		
Accrued construction expenditures	101	85
Capital leases	2	3
Nuclear fuel purchase	—	97

See Notes to Condensed Consolidated Financial Statements.

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SOUTH CAROLINA ELECTRIC & GAS COMPANY
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
For the Three and Six Months Ended June 30, 2014 and 2013
(Unaudited)

The following notes should be read in conjunction with the Notes to Consolidated Financial Statements appearing in SCE&G's Annual Report on Form 10-K for the year ended December 31, 2013. These are interim financial statements and, due to the seasonality of Consolidated SCE&G's business and matters that may occur during the rest of the year, the amounts reported in the Condensed Consolidated Statements of Income are not necessarily indicative of amounts expected for the full year. In the opinion of management, the information furnished herein reflects all adjustments, all of a normal recurring nature, which are necessary for a fair statement of the results for the interim periods reported.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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.

Variable Interest Entities

SCE&G has determined that it is the primary beneficiary of GENCO and Fuel Company (which are considered to be VIEs) and, accordingly, the accompanying condensed 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 condensed consolidated financial statements.

GENCO owns a coal-fired electric generating station with a 605 MW 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 $473 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 allowances. See also Note 4.

Plant to be Retired

As previously disclosed, in 2012, SCE&G identified 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. Three of these units had been retired by December 31, 2013, 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 condensed 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 use and in rate base, and SCE&G depreciates them using composite straight-line rates approved by the SCPSC.

New Accounting Matter

In May 2014, the Financial Accounting Standards Board issued new accounting guidance for revenue arising from contracts with customers that supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized, and will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services. Consolidated SCE&G will be required to adopt the new guidance in the first quarter of 2017, and early adoption is not permitted. Consolidated SCE&G has not determined the impact this guidance will have on its results of operations, cash flows or financial position.

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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 connection with its annual review of base rates for fuel costs, and by order dated April 30, 2013, the SCPSC approved a settlement agreement among SCE&G, the ORS and the SCEUC in which SCE&G agreed to reduce its environmental fuel cost component effective with the first billing cycle of May 2013. The order also provided for the accrual of certain debt-related carrying costs on a portion of SCE&G's under-collected balance of fuel costs and approved SCE&G's total fuel cost component.

By order dated April 29, 2014, the SCPSC approved a settlement agreement among SCE&G, the ORS and SCEUC in which SCE&G agreed to increase its base fuel cost component by approximately $10.3 million for the 12-month period beginning with the first billing cycle of May 2014. The SCPSC's order also provides for, among other things, the application of approximately $46 million in deferred gains from the late 2013 settlement of certain interest rate swaps, previously recorded as regulatory liabilities, to reduce the under-collected balance of fuel costs in April 2014 and the accrual of certain debt-related carrying costs on its under-collected balance of fuel costs during the period May 1, 2014 through April 30, 2015.

The increase to the base fuel cost component was offset by a reduction in SCE&G’s rate rider related to pension costs, which was approved by the SCPSC in March 2014. The reduction was requested by SCE&G as a result of the lower net periodic benefit cost it expects to record during 2014. See also Note 8.

The cost of fuel includes amounts paid by SCE&G pursuant to the Nuclear Waste Act for the disposal of spent nuclear fuel. As a result of a November 2013 decision by the Court of Appeals, the DOE set the Nuclear Waste Act fee to zero effective May 16, 2014. By order of the SCPSC, the impact of this action will be considered in future cost of fuel rate adjustments.

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. During the three and six months ended June 30, 2014, $1.4 million and $2.5 million, respectively, 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 deferred income tax 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.

SCE&G files an IRP with the SCPSC annually which evaluates future electric generation needs based on several 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 retired or intends to retire by 2018, subject to future developments in environmental regulations, among other matters. Three of these units had been retired by December 31, 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. See also Note 1.

SCE&G's DSM Programs for electric customers provide for an annual rider, approved by the SCPSC, to allow recovery of the costs and net lost margin revenues 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 margin revenues, program costs, incentives and net program benefits. The SCPSC approved the following rate changes pursuant to annual DSM Programs filings, which went into effect as indicated:

Year	Effective	Amount
2014	First billing cycle of May	$15.4 million
2013	First billing cycle of May	$16.9 million
2012	First billing cycle of May	$19.6 million

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

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

- By order dated April 30, 2014, in response to SCE&G's annual DSM Programs filing, the SCPSC approved SCE&G's 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 late 2013 settlement of certain interest rate derivative instruments, previously deferred as regulatory liabilities, to offset a portion of the net lost margin revenues component of SCE&G's DSM Programs rider, and (3) apply $5.0 million of its storm damage reserve and $5.0 million of the gains from the settlement of certain interest rate derivative instruments, to the remaining balance of deferred net lost margin revenues as of April 30, 2014, which had been deferred within regulatory assets resulting from the May 2013 order previously described. In addition, the SCPSC, upon recommendation of the ORS, reduced by 25%, or $6.6 million, the amount of net lost margin revenues SCE&G expects to experience over the 12-month period beginning with the first billing cycle of May 2014, and ordered that the $6.6 million be applied to decrease the amount of program costs deferred for recovery. Actual net lost margin revenues not collected in the current DSM Programs rate rider are subject to true up in the following program year.

Electric – BLRA

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 years indicated:

Year	Action		Amount
2013	2.9	% Increase	$67.2 million
2012	2.3	% Increase	$52.1 million

On May 30, 2014, SCE&G filed its annual request for approval of revised rates under the provisions of the BLRA. On July 30, 2014, ORS filed a report of its review of SCE&G's request. ORS proposes that SCE&G be allowed to increase its rates in the amount of $66.2 million, or 2.82%. If approved, the revised rates will be effective for bills rendered on and after October 30, 2014.

Gas

The RSA is designed to reduce the volatility of costs charged to customers by allowing for 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 years indicated:

Year	Action		Amount
2013	No change		-
2012	2.1	% Increase	$7.5 million

On June 13, 2014, SCE&G filed with the SCPSC its quarterly monitoring report for the twelve-month period ended March 31, 2014, and proposed a $3.0 million, or 0.7%, overall decrease to its natural gas rates under the terms of the RSA. The ORS is expected to issue an audit report by September 1, 2014 and the SCPSC is to issue its order by October 15, 2014. If approved, the rate adjustment will be effective for the first billing cycle in November 2014.

SCE&G's natural gas tariffs include a PGA clause 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 review conducted for the 12-month period ended July 31, 2013 resulted in the SCPSC issuing an order finding that SCE&G's gas purchasing policies and practices during the review period were reasonable and prudent. The next annual PGA hearing is scheduled for November 6, 2014.

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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 regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

Millions of dollars	June 30, 2014	December 31, 2013
Regulatory Assets:		
Accumulated deferred income taxes	$252	$256
Under collections – electric fuel adjustment clause	55	18
Environmental remediation costs	36	37
AROs and related funding	357	350
Franchise agreements	28	31
Deferred employee benefit plan costs	209	215
Planned major maintenance	7	—
Deferred losses on interest rate derivatives	284	124
Deferred pollution control costs	36	37
Unrecovered plant	140	145
DSM Programs	50	51
Other	45	39
Total Regulatory Assets	$1,499	$1,303
Regulatory Liabilities:		
Accumulated deferred income taxes	18	19
Asset removal costs	505	495
Storm damage reserve	7	27
Deferred gains on interest rate derivatives	83	181
Planned major maintenance	—	10
Total Regulatory Liabilities	$613	$732

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 during annual hearings which are not expected to be recovered in retail electric rates within 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, distribution and other properties. 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 an SCPSC order, SCE&G is recovering these amounts through cost of service rates through 2021.

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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, as well as costs deferred pursuant to specific SCPSC regulatory orders. In connection with a 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 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 and accrues $18.4 million annually for fossil fueled turbine/generation equipment maintenance and collects and accrues $17.2 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 made or 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 over periods up to approximately 50 years except when, in the case of deferred gains, such amounts are applied otherwise at the direction of the SCPSC. Also, in 2014, as discussed at Rate Matters - Electric - Cost of Fuel and Rate Matters - Electric - Base Rates, certain of these deferred amounts were applied to offset under-collected fuel balances and unrecorded net lost margin revenues related to DSM Programs.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the scrubbers installed at certain coal-fired generating plants pursuant to specific regulatory orders. Such costs are being recovered through utility rates through 2045.

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 through 2025. Unamortized amounts are included in rate base and are earning a current return.

DSM Programs represent deferred costs associated with such programs at SCE&G. As a result of an April 2014 SCPSC order, deferred costs are currently being recovered over approximately ten years through a SCPSC approved rider. See Rate Matters - Electric - Base Rates above for details regarding a 2014 filing with the SCPSC regarding recovery of these deferred costs.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 33 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of 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. In 2014, $15.5 million of the reserve was applied to offset incremental storm damage costs. Also, as discussed at Rate Matters - Electric - Base Rates, in April 2014 $5.0 million of the reserve was applied to offset unrecovered net lost margin revenues related to DSM Programs.

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 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.

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3. EQUITY

Changes in common equity during the six months ended June 30, 2014 and 2013 were as follows:

Millions of dollars	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Equity
Balance at January 1, 2014	$2,479	$1,896	$(3)	$117	$4,489
Earnings available to common shareholder		219		6	225
Deferred cost of employee benefit plans			—		—
Total Comprehensive Income		219	—	6	225
Capital contributions from parent	55				55
Cash dividend declared		(125)		(3)	(128)
Balance at June 30, 2014	$2,534	$1,990	$(3)	$120	$4,641
Balance at January 1, 2013	$2,167	$1,766	$(4)	$114	$4,043
Earnings available to common shareholder		174		6	180
Deferred cost of employee benefit plans			—		—
Total Comprehensive Income		174	—	6	180
Capital contributions from parent	255				255
Cash dividend declared		(124)		(4)	(128)
Balance at June 30, 2013	$2,422	$1,816	$(4)	$116	$4,350

SCE&G had 50 million shares of common stock authorized as of June 30, 2014 and December 31, 2013, of which 40.3 million were issued and outstanding during all periods presented. SCE&G had 20 million shares of preferred stock authorized as of June 30, 2014 and December 31, 2013, of which 1,000 shares at a stated value of $100,000 were issued and outstanding during all periods presented. All issued and outstanding shares of SCE&G's common and preferred stock are held by SCANA.

Reclassifications from AOCI into earnings of the amortization of deferred employee benefit costs were not significant for any period presented.

4. LONG-TERM DEBT AND LIQUIDITY

Long-term Debt

In May 2014, SCE&G issued $300 million of 4.5% first mortgage bonds due June 1, 2064. Proceeds from this sale 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 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 at a premium, for the benefit of SCE&G, $39.5 million of 4.00% 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.

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

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Liquidity

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	June 30, 2014		December 31, 2013	
Lines of credit:				
Total committed long-term	$1,400		$1,400	
Outstanding commercial paper (270 or fewer days)	$316		$251	
Weighted average interest rate	0.27	%	0.27	%
Letters of credit supported by LOC	$0.3		$0.3	
Available	$1,084		$1,149	

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 a party to a three-year credit agreement in the amount of $200 million. 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 $1.4 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. 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. The letters of credit expire, subject to renewal, in the fourth quarter of 2014.

Consolidated SCE&G participates in a utility money pool. Money pool borrowings and investments bear interest at short-term market rates. Consolidated SCE&G's interest income and expense from money pool transactions were not significant for any period presented. At June 30, 2014 and December 31, 2013, Consolidated SCE&G had outstanding money pool borrowings from an affiliate of $78.3 million and $27.3 million, respectively.

5. INCOME TAXES

During 2013 SCANA amended certain of its consolidated 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 $3.0 million. During 2014 SCANA amended additional tax returns to claim certain tax-defined research and development deductions and credits. In connection with these filings, Consolidated SCE&G increased its unrecognized tax benefit by $6.7 million (for a total of $9.7 million). If recognized, this tax benefit would affect Consolidated SCE&G's effective tax rate. No other material changes in the status of Consolidated SCE&G's tax positions have occurred through June 30, 2014.

Consolidated SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. Because no refunds related to the unrecognized tax benefits have yet been received, Consolidated SCE&G has not recorded any interest expense or penalties associated with them.

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 Consolidated SCE&G's financial position, results of operations or cash flows.

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6. DERIVATIVE FINANCIAL INSTRUMENTS

Consolidated SCE&G recognizes all derivative instruments as either assets or liabilities in the statement 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 the 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, 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, may be amortized to interest expense or may be applied as otherwise directed by the SCPSC.

Cash payments made or received upon termination 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 an aggregate notional amount of $36.4 million at June 30, 2014 and $36.4 million at December 31, 2013. Consolidated SCE&G was party to interest rate swaps not designated as cash flow hedges with an aggregate notional amount of $1.1 billion at June 30, 2014 and $1.3 billion at December 31, 2013, respectively.

The fair value of interest rate derivatives was reflected in the condensed consolidated balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet	Fair	Balance Sheet	Fair
Millions of dollars	Location	Value	Location	Value
As of June 30, 2014				
Derivatives designated as hedging instruments				
Interest rate contracts				$1

			Derivative financial instruments	
			Other deferred credits and other liabilities	4
Total				$5
Derivatives not designated as hedging instruments				
Interest rate contracts	Other deferred debits and other assets	$2	Derivative financial instruments	$82
			Other deferred credits and other liabilities	38
Total		$2		$120
As of December 31, 2013				
Derivatives designated as hedging instruments				
Interest rate contracts			Derivative financial instruments	$1
Total				$1
Derivatives not designated as hedging instruments				
Interest rate contracts	Prepayments and other	$13	Derivative financial instruments	$1
	Other deferred debits and other assets	19		
Total		$32		$1

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

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Deferred in Regulatory Accounts (Effective Portion)			Loss Reclassified from Deferred Accounts into Income (Effective Portion)	
Millions of dollars	2014	2013	Location	2014	2013
Three Months Ended June 30,					
Interest rate contracts	$(1)	$61	Interest expense	—	—
Six Months Ended June 30,					
Interest rate contracts	$(4)	$96	Interest expense	$(1)	$(1)

Hedge Ineffectiveness

Other gains (losses) recognized in income representing ineffectiveness on interest rate hedges designated as cash flow hedges were insignificant in each of the three and six months ended June 30, 2014 and 2013, respectively.

Derivatives not designated as Hedging Instruments

Millions of dollars	Loss Deferred in Regulatory Accounts	Gain Reclassified from Deferred Accounts into Income	
		Location	Amount
Three Months Ended June 30, 2014			

Interest rate contracts	$(73)	Other income	$55
Six Months Ended June 30, 2014			
Interest rate contracts	$(185)	Other income	$55

For the three and six months ended June 30, 2013, no losses were deferred in regulatory accounts, and no amounts were reclassified from deferred accounts into income. As of June 30, 2014, Consolidated SCE&G expects that during the next 12 months reclassifications from other current liabilities and deferred regulatory accounts to earnings arising from derivatives not designated as hedges will include $14.1 million as an increase to other income. The effect of this increase on net income will be entirely offset by net lost margin revenues from DSM Programs as further described 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 may 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 permit the secured party to demand the posting of 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 may require Consolidated SCE&G to provide collateral upon the occurrence of specific events, primarily credit downgrades. As of June 30, 2014 and December 31, 2013, Consolidated SCE&G has posted $17.9 million and $1.5 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 condensed consolidated balance sheets. Collateral related to noncurrent positions is recorded in Other within Deferred Debits and Other Assets on the condensed consolidated balance sheets. If all of the contingent features underlying these instruments had been fully triggered as of June 30, 2014 and December 31, 2013, Consolidated SCE&G could have been required to post an additional $105.3 million and $- , respectively, of collateral with its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of June 30, 2014 and December 31, 2013 is $123.1 million and $1.0 million, respectively.

In addition, as of June 30, 2014 and December 31, 2013, 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 were fully triggered as of June 30, 2014 and December 31, 2013, Consolidated SCE&G could request $- and $31.7 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 June 30, 2014 and December 31, 2013 is $- and $31.7 million, respectively.

Information related to Consolidated SCE&G's derivative assets follows:

				Gross Amounts Not Offset in the Statement of Financial Position		
Millions of dollars	Gross Amounts of Recognized	Gross Amounts Offset in the	Net Amounts Presented in the	Financial Instruments	Cash Collateral	Net Amount

	Assets	Statement of Financial Position	Statement of Financial Position			Received
As of June 30, 2014						
Interest rate contracts	$2	—	$2	$(2)	—	—
Balance Sheet Location	Other deferred debits and other assets		$2			
	Total		$2			
As of December 31, 2013						
Interest rate contracts	$32	—	$32	$(1)	—	$31
Balance Sheet Location	Prepayments and other		$13			
	Other deferred debits and other assets		19			
	Total		$32			

Information related to Consolidated SCE&G's derivative liabilities follows:

				Gross Amounts Not Offset in the Statement of Financial Position		
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	Financial Instruments	Cash Collateral Posted	Net Amount
As of June 30, 2014						
Interest rate contracts	$125	—	$125	$(2)	$(18)	$105
Balance Sheet Location	Derivative financial instruments		$83			
	Other deferred credits and other liabilities		42			
	Total		$125			
As of December 31, 2013						
Interest rate contracts	$2	—	$2	$(1)	$(1)	—
Balance Sheet Location	Derivative financial instruments		$2			
	Total		$2			

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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:

Millions of dollars		June 30, 2014	December 31, 2013
Assets -	Interest rate contracts	$2	$32
Liabilities -	Interest rate contracts	125	2

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 June 30, 2014 and December 31, 2013 were as follows:

	June 30, 2014		December 31, 2013	
Millions of dollars	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	$4,343.1	$4,975.1	$4,054.9	$4,433.0

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 fair value, and are based on quoted prices from dealers in the commercial paper market. The resulting fair value is considered to be Level 2.

8. EMPLOYEE BENEFIT PLANS

Pension and Other Postretirement Benefit Plans

Consolidated SCE&G participates in SCANA's noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees, and also participates in SCANA's unfunded postretirement health care and life insurance programs, which provide benefits to active and retired employees. Components of net periodic benefit cost recorded by Consolidated SCE&G were as follows:

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	2014	2013	2014	2013
Three months ended June 30,				
Service cost	$4.0	$4.8	$1.0	$1.3
Interest cost	8.6	8.0	2.4	2.2
Expected return on assets	(14.1)	(13.0)	—	—
Prior service cost amortization	0.8	1.4	0.1	0.1
Amortization of actuarial losses	1.1	4.6	0.1	0.7
Net periodic benefit cost	$0.4	$5.8	$3.6	$4.3
Six months ended June 30,				
Service cost	$8.0	$9.6	$2.0	$2.5
Interest cost	17.2	16.0	4.8	4.4
Expected return on assets	(28.3)	(26.0)	—	—
Prior service cost amortization	1.7	2.8	0.2	0.3

Amortization of actuarial losses	2.2	9.2	0.2	1.3
Net periodic benefit cost	$0.8	$11.6	$7.2	$8.5

No significant contribution to the pension trust is expected for the foreseeable future, nor is a limitation on benefit payments expected to apply. SCE&G recovers current pension costs through either a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations. Certain pension costs arising prior to 2013 were deferred for future recovery under regulatory orders as discussed in Note 2.

9. 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 SCE&G'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 premium, SCE&G’s portion of the retrospective premium assessment would not exceed $43.5 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's 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 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. As of June 30, 2014, SCE&G's 55% share of the estimated cash outlays (future value, excluding AFC) totaled approximately $5.3 billion for plant and related transmission infrastructure costs, and was 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 from Santee Cooper. 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. As of June 30, 2014, and based on the updated construction milestone schedule and capital costs schedule approved by the SCPSC in November 2012 (see below), SCE&G estimates such cost 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 for the additional ownership interest would be reflected in a revised rates filing under the BLRA.

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Under the BLRA, the SCPSC has approved, among other things, the construction milestone schedule and capital costs estimates schedule for the New Units. The effect of this approval is that it constitutes a final and binding determination that the New Units are used and useful for utility purposes, and that the capital costs associated with the New Units are prudent utility costs and expenses and are properly included in rates, so long as the New Units are constructed or are being constructed within the parameters of the approved construction milestone schedule, including specified contingencies, and the approved capital costs estimates schedule. The BLRA provides that SCE&G may apply to the SCPSC annually for an order to recover through revised rates SCE&G’s weighted average cost of capital applied to all or part of the outstanding balance of construction work in progress concerning the New Units. Such annual rate changes are described in Note 2.

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 have impacted the project budget and schedule. SCE&G expects to resolve all disputes through both the informal and formal procedures and anticipates that any costs that arise through such dispute resolution processes, as well as other costs identified from time to time, will be recoverable through rates.

In November 2012, the SCPSC approved a petition by SCE&G under the BLRA for an updated construction milestone schedule and additional updated capital costs for the New Units. In addition, the SCPSC 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 known claims by the Consortium 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. Immediately thereafter, two parties filed separate petitions requesting that the SCPSC reconsider its order, and 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, contending that the SCPSC erred in granting approval of the updated capital costs for the New Units. The South Carolina Supreme Court heard arguments related to those appeals on April 16, 2014. SCE&G is unable to predict the outcome of these appeals.

The substantial completion dates currently approved by the SCPSC for Units 2 and 3 are March 15, 2017 and May 15, 2018. The SCPSC has also approved an 18-month contingency period beyond each of these dates.

Since the settlement of delay-related claims in 2012, the Consortium has continued to experience delays in the schedule for fabrication and delivery of sub-modules for the New Units. The fabrication and delivery of sub-modules have been and remain 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, as well as shield building modules, are considered critical path items for both New Units. CA20 was placed on the nuclear island of Unit 2 in May 2014. 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 Unit 2 during the first half of 2015.

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 schedules 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, construction work crew efficiencies, and other items. The result will be a revised fully integrated project schedule with timing of specific construction activities along with detailed information on budget, cost and cash flow requirements. While this detailed re-baselining of construction schedules has not been completed, in August 2014 SCE&G received preliminary information in which the Consortium has indicated that the substantial completion of Unit 2 is expected to occur in late 2018 or the first half of 2019 and that the substantial completion of Unit 3 may be approximately 12 months later. These expected substantial completion dates do not reflect all efforts that may be possible to mitigate delay nor has SCE&G accepted this new schedule. The Consortium has not yet provided any cost estimates related to the delay. SCE&G anticipates that the revised schedule and the cost estimate at completion will be finalized in the latter half of 2014. SCE&G plans to reevaluate and reschedule its owners cost estimates and cash flow requirements in light of that new schedule when it is finalized.

SCE&G cannot predict with certainty the extent to which the delays in the substantial completion of the New Units will result in increased project costs. SCE&G has not accepted responsibility for any delay-related costs and expects to have 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 facility, which will also be included in discussions with the Consortium.

The construction milestone schedule approved by the SCPSC in November 2012 provides for 146 construction milestone dates, which are each subject to an 18-month schedule contingency. As of August 4, 2014, 100 milestones have been completed. Based on the preliminary schedule information arising from the re-baselining effort, the completion dates for a

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number of the remaining milestones are expected to extend beyond the 18-month contingency periods. As a result, upon completion of the re-baselining and the finalization of the revised schedule and cost estimate at completion, SCE&G, as provided for under the BLRA, expects to petition the SCPSC for an order to update the BLRA construction milestone schedule and/or capital costs estimates schedule. The BLRA provides that the SCPSC shall grant the petition for modification if the record justifies a finding that the change is not the result of imprudence by SCE&G.

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 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 each of the New Units (advanced nuclear units, as defined), to the extent that such Unit is operational before January 1, 2021, 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 Unit 2 and November 2013 for Unit 3), 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 can 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 foreseeable future.

The Memorandum also directed the EPA to issue standards, regulations, or guidelines for existing units. On June 2, 2014, the EPA released the Clean Power Plan proposed to regulate carbon dioxide emissions from existing units. The proposed rule includes state specific rate-based goals for carbon dioxide emissions, as well as guidelines for states to follow in developing SIPs to achieve those goals. Consolidated SCE&G is evaluating the proposed rule which may be revised before it becomes final in June, 2015. As currently proposed, states will have from one to three years from the date of any final rule to issue SIPs that will ultimately define the specific compliance methodology that will be applied to existing units in that state. Consolidated SCE&G expects that any costs incurred to comply with GHG emission requirements will be recoverable through rates.

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 Court of Appeals 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. On April 29, 2014, the U. S. Supreme Court reversed the judgment of the Court of Appeals and CSAPR was remanded to the Court of Appeals for further proceedings consistent with the U. S. Supreme Court opinion. On June 26, 2014, the EPA filed a motion with the Court of Appeals to lift the stay of the CSAPR. While the motion is being considered, CAIR remains in place and no immediate action from states or affected sources is expected. 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.

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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. Consolidated 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 September 30, 2015. The EPA expects compliance within a three to six year time frame as NPDES permits are renewed.

On May 19, 2014, the EPA finalized a rule that modifies requirements for existing cooling water intake structures. The rule becomes effective 60 days after publication in the Federal Register. 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 Consolidated SCE&G. 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 and subsequent obligation via consent decree, the EPA committed to issue new federal regulations affecting the management and disposal of CCRs, such as ash, by December 19, 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 June 30, 2014, 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 is constructing 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. See Note 2.

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. 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.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of byproduct 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 million, which is accrued in Other within Deferred Credits and Other Liabilities on the condensed consolidated balance sheet. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates. At June 30, 2014, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $36.4 million and are included in regulatory assets.

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10. AFFILIATED TRANSACTIONS

CGT transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $14.7 million and $16.9 million for the six months ended June 30, 2014 and 2013, respectively. SCE&G had approximately $3.1 million and $3.3 million payable to CGT for transportation services at June 30, 2014 and December 31, 2013, respectively. SCE&G had approximately $2.7 million and $1.3 million receivable from CGT for transportation services at June 30, 2014 and December 31, 2013, respectively.

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 $107.3 million and $89.3 million for the six months ended June 30, 2014 and 2013, respectively. SCE&G's payables to SEMI for such purposes were $16.8 million and $12.5 million as of June 30, 2014 and December 31, 2013, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC, which is involved in the manufacturing and sale of refined coal to reduce emissions. SCE&G accounts for this investment using the equity method. SCE&G's receivable from this affiliate was $25.0 million at June 30, 2014 and $18.0 million at December 31, 2013. SCE&G's payable to this affiliate was $25.2 million at June 30, 2014 and $18.0 million at December 31, 2013. SCE&G's total purchases from this affiliate were $109.5 million and $31.8 million for the six months ended June 30, 2014 and 2013, respectively. SCE&G's total sales to this affiliate were $108.9 million and $31.6 million for the six months ended June 30, 2014 and 2013, respectively.

SCANA Services provides the following services to Consolidated SCE&G, which are rendered at direct or allocated cost: information systems services, telecommunications 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, general administrative services, and retirement benefits. In addition, SCANA Services processes and pays invoices for Consolidated SCE&G and is reimbursed. Costs for these services were $146.4 million and $145.7 million for the six months ended June 30, 2014 and 2013, respectively. Consolidated SCE&G's payables to SCANA Services for these services were $43.8 million and $49.1 million at June 30, 2014 and December 31, 2013, respectively.
Money pool borrowings from an affiliate are described in Note 4.

11. SEGMENT OF BUSINESS INFORMATION

Consolidated SCE&G's reportable segments are listed in the following table. Consolidated SCE&G uses operating income to measure profitability for its regulated operations. Therefore, earnings available to common shareholder are not allocated to the Electric Operations and Gas Distribution segments. Intersegment revenues were not significant.

Millions of dollars	External Revenue	Operating Income	Earnings Available to Common Shareholder
Three Months Ended June 30, 2014			
Electric Operations	$612	$143	n/a
Gas Distribution	86	2	n/a
Adjustments/Eliminations	—	—	$96
Consolidated Total	$698	$145	$96
Six Months Ended June 30, 2014			
Electric Operations	$1,292	$341	n/a
Gas Distribution	265	42	n/a
Adjustments/Eliminations	—	—	$219
Consolidated Total	$1,557	$383	$219

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Three Months Ended June 30, 2013			
Electric Operations	$612	$178	n/a
Gas Distribution	84	2	n/a
Adjustments/Eliminations	—	—	$85
Consolidated Total	$696	$180	$85
Six Months Ended June 30, 2013			
Electric Operations	$1,197	$331	n/a
Gas Distribution	227	40	n/a
Adjustments/Eliminations	—	—	$174
Consolidated Total	$1,424	$371	$174

Segment Assets	June 30, 2014	December 31, 2013
Electric Operations	$9,724	$9,488
Gas Distribution	698	686
Adjustments/Eliminations	2,787	2,526
Consolidated Total	$13,209	$12,700

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

SOUTH CAROLINA ELECTRIC & GAS COMPANY

The following discussion should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations appearing in SCE&G's Annual Report on Form 10-K for the year ended December 31, 2013.

RESULTS OF OPERATIONS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014
AS COMPARED TO THE CORRESPONDING PERIODS IN 2013

Net Income

Net income for Consolidated SCE&G was as follows:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Net income	$99.5	13.1 %	$88.0	$225.7	25.5 %	$179.8

Second Quarter

Net income increased primarily due to the effects of weather and base rate increases under the BLRA. These increases were partially offset by higher operation and maintenance expenses, higher property taxes, and higher interest cost, as further discussed below.

Year to Date

Net income increased due to higher electric and gas margins and other revenue. These margin increases were partially offset by higher operation and maintenance expenses, higher depreciation expense, higher interest cost and higher property taxes, as 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 2014:

Declaration Date	Amount	Quarter Ended	Payment Date
February 20, 2014	$64.3 million	March 31, 2014	April 1, 2014
April 24, 2014	$64.4 million	June 30, 2014	July 1, 2014
July 31, 2014	$68.5 million	September 30, 2014	October 1, 2014

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:

	Second Quarter	Year to Date

Millions of dollars	2014	Change		2013	2014	Change		2013
Operating revenues	$612.4	0.1	%	$611.6	$1,292.3	7.9	%	$1,197.2
Less: Fuel used in generation	212.7	12.4	%	189.2	426.5	13.2	%	376.9
Purchased power	16.3	85.2	%	8.8	41.3	*		15.8
Margin	$383.4	(7.3	)%	$413.6	$824.5	2.5	%	$804.5

* Greater than 100%

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Second Quarter

Pursuant to orders of the SCPSC, electric margin was adjusted downward by $60.1 million related to fuel cost recovery and SCE&G's DSM Programs. These adjustments are fully offset by the recognition, within other income, of gains realized upon the late 2013 settlement of certain derivative interest rate contracts and the application, as a reduction to operation and maintenance expenses, of a portion of SCE&G's storm damage reserve, both of which had been deferred in regulatory accounts. The electric margin decrease was partially offset by the effects of weather of $13.4 million, base rate increases under the BLRA of $12.2 million and customer growth of $3.8 million.

Year to Date

Electric margin increased due to the effects of weather of $33.5 million, base rate increases under the BLRA of $24.8 million and customer growth of $7.7 million. These margin increases were partially offset by the $60.1 million downward adjustment to electric revenues pursuant to the SCPSC orders previously discussed.

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

	Second Quarter			Year to Date		
Classification	2014	Change	2013	2014	Change	2013
Residential	1,904	6.7 %	1,784	4,055	11.3 %	3,642
Commercial	1,825	2.7 %	1,777	3,575	3.7 %	3,446
Industrial	1,542	1.6 %	1,518	2,994	2.5 %	2,921
Other	149	3.5 %	144	290	3.9 %	279
Total Retail Sales	5,420	3.8 %	5,223	10,914	6.1 %	10,288
Wholesale	235	3.1 %	228	479	(2.4)%	491
Total Sales	5,655	3.7 %	5,451	11,393	5.7 %	10,779

Second Quarter

Retail sales volume increased primarily due to the effects of weather and customer growth.

Year to Date

Retail sales volume increased primarily due to the effects of weather and customer growth. The decrease in wholesale sales is primarily due to the expiration of a customer contract.

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:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Operating revenues	$86.0	2.1 %	$84.2	$264.9	16.7 %	$226.9
Less: Gas purchased for resale	55.5	1.6 %	54.6	164.7	25.1 %	131.7
Margin	$30.5	3.0 %	$29.6	$100.2	5.3 %	$95.2

Second Quarter

Margin increased primarily due to residential and commercial customer growth. SCE&G's WNA mitigates weather-related fluctuations in margin but has no impact on volumes.

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Year to Date

Margin increased primarily due to residential and commercial customer growth of $2.3 million and increased average usage of $2.4 million.

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

	Second Quarter			Year to Date		
Classification (in thousands)	2014	Change	2013	2014	Change	2013
Residential	1,140	(9.6)%	1,261	9,579	24.1%	7,719
Commercial	2,599	(1.7)%	2,644	7,783	12.2%	6,938
Industrial	4,694	(7.6)%	5,081	9,214	(11.8)%	10,450
Transportation	1,210	6.9%	1,132	1,864	(23.9)%	2,449
Total	9,643	(4.7)%	10,118	28,440	3.2%	27,556

Second Quarter

Residential and commercial sales volumes decreased primarily due to the effects of weather. Industrial sales volumes decreased due to a customer switching to an alternative fuel source. Transportation sales volumes increased due to an increase in the average number of transport customers.

Year to Date

Residential and commercial sales volumes increased primarily due to the effects of weather. Industrial sales volumes decreased due to weather related curtailments and a customer switching to an alternate fuel source. Transportation sales volumes decreased due to weather related curtailments.

Other Operating Expenses

Other operating expenses were as follows:

	Second Quarter			Year to Date		
Millions of dollars	2014	Change	2013	2014	Change	2013
Other operation and maintenance	$137.8	1.8%	$135.4	$279.5	2.1%	$273.8
Depreciation and amortization	78.5	(0.1)%	78.6	156.6	0.3%	156.2
Other taxes	51.6	4.2%	49.5	105.0	6.0%	99.1

Second Quarter

Other operation and maintenance expenses increased primarily due to higher labor expenses, including incentive compensation. Other taxes increased primarily due to higher property taxes.

Year to Date

Other operation and maintenance expenses increased primarily due to higher labor expenses, including incentive compensation, of $1.9 million, and storm expenses of $1.8 million. Depreciation and amortization expense increased due to net plant additions. Other taxes increased primarily due to higher property taxes.

Other Revenue (Expense)

Other revenue (expense) includes the results of certain incidental (non-utility) activities and 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), both of which have the effect of increasing reported net income. Other revenue increased primarily due to the recognition of $55.1 million of gains realized upon the late 2013 settlement of certain interest rate derivative contracts previously recorded as regulatory liabilities pursuant to

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SCPSC orders previously discussed. Such gain recognition was fully offset by downward adjustments to revenues reflected within electric margin and had no effect on net income.

Interest Expense

Interest charges increased primarily due to increased borrowings.

Income Taxes

Income taxes for the three and six months ended June 30, 2014 were higher than the same periods in 2013 primarily due to higher income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated SCE&G anticipates that its cash obligations will be met through internally generated funds, the incurrence of additional short- and long-term indebtedness, and equity contributions from its parent company. 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 six and 12 months ended June 30, 2014 was 3.80 and 3.72, respectively.

SCE&G received approximately $55 million during the six months ended June 30, 2014 as an equity contribution from its parent company.

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.

At June 30, 2014, Consolidated SCE&G had net available liquidity of approximately $1.1 billion, comprised of cash on hand and available amounts under lines of credit. The credit agreements total an aggregate of $1.4 billion, of which $200 million is scheduled to expire in October 2016 and the remainder is scheduled to expire in October 2018. Consolidated SCE&G regularly monitors the commercial paper and short-term credit markets to optimize the timing of repayment of outstanding balances on its draws, if any, from the credit facilities. Consolidated SCE&G’s long term debt portfolio has a weighted average maturity of approximately 22 years and bears an average interest cost of 5.6%. Substantially all of the 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 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 and is expected to be renewed.

SCE&G's current preliminary estimates of its capital expenditures for new nuclear construction (including transmission) for 2014 through 2016, which are subject to continuing review and adjustment, are $805 million in 2014, $930 million in 2015, and $696 million in 2016.

OTHER MATTERS

In June 2014, the Distributed Energy Resource Act became law in South Carolina. Among other things, this law (i) authorizes SCE&G, at its discretion, to implement a distributed energy resource program and recover the reasonable and prudent costs incurred in implementing such a program, (ii) permits non-utilities and utilities to lease renewable electric generation facilities to homeowners and businesses, and (iii) requires the SCPSC to establish a net energy metering rate methodology. SCE&G is actively participating, along with numerous other stakeholders, in the SCPSC's net energy metering proceeding, which is expected to continue into 2015. As for implementing a distributed energy program, SCE&G is evaluating its options under the law.

For information related to environmental matters, nuclear generation, and claims and litigation, see Note 9 to the condensed consolidated financial statements.

ITEM 4. CONTROLS AND PROCEDURES

As of June 30, 2014, SCE&G conducted an evaluation under the supervision and with the participation of its management, including its CEO and CFO, of (a) the effectiveness of the design and operation of its disclosure controls and procedures and (b) any change in its internal control over financial reporting. Based on this evaluation, the CEO and CFO concluded that, as of June 30, 2014, SCE&G's disclosure controls and procedures were effective. There has been no change in SCE&G's internal control over financial reporting during the quarter ended June 30, 2014, that has materially affected or is reasonably likely to materially affect SCE&G's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 5. OTHER INFORMATION

SCANA and SCE&G:

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 links to the New Nuclear Development and Other Investor Information sections of the website. The New Nuclear Development section in turn contains a yellow box with a link to project news and updates. The Other Investor Information section of the website contains a link to recent investor related information that cannot be found at other areas of the website. 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. Investors, media and others interested in SCE&G's new nuclear project are encouraged to review this information and can sign up, under the Investor Relations Section 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) for an email alert when there is a new posting in the New Nuclear Development and Other Investor Information yellow box.

ITEM 6. EXHIBITS

SCANA and SCE&G:

Exhibits filed or furnished with this Quarterly Report on Form 10-Q are listed in the following Exhibit Index.

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 percent 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each of the registrants has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of each registrant shall be deemed to relate only to matters having reference to such registrant and any subsidiaries thereof.

SCANA CORPORATION
SOUTH CAROLINA ELECTRIC & GAS COMPANY
(Registrants)

	By:	/s/James E. Swan, IV
Date: August 11, 2014		James E. Swan, IV
		Controller
		(Principal accounting officer)

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EXHIBIT INDEX

Exhibit No.	Applicable to Form 10-Q 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 Number 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)
12.01	X	X	Statement Re Computation of Ratios (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

* 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.

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