

MISSION: POSSIBLE

ANNUAL REPORT
2015

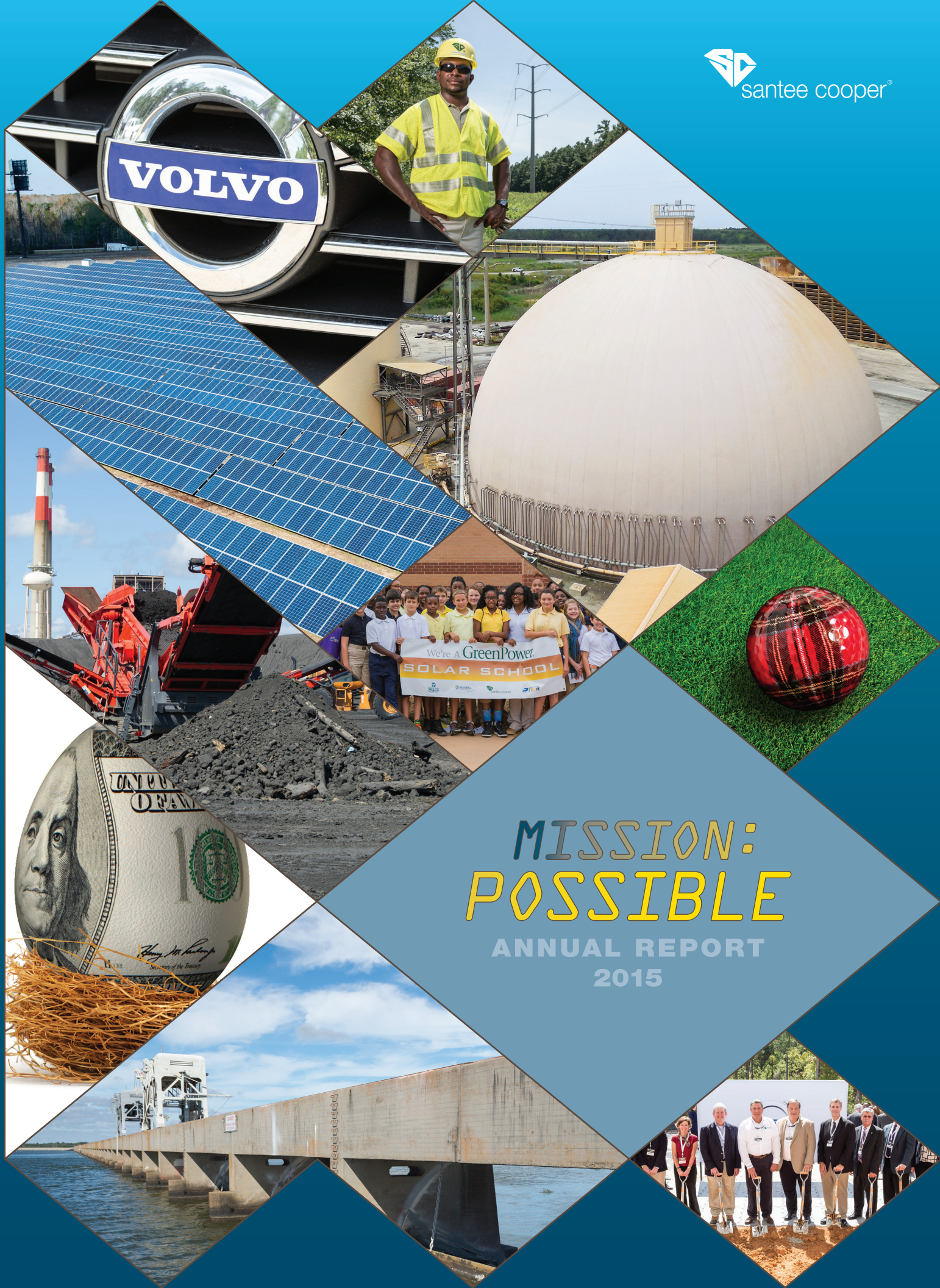


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CHAIRMAN AND CEO LETTER



At 5 p.m. on May 10, 2015, members of the Santee Cooper Board of Directors gathered by telephone for what was probably the first Santee Cooper Board meeting held on a Mother's Day. Unusual times call for unusual measures: It isn't every year that Volvo places a new automobile manufacturing facility.

Santee Cooper's Board gathered that Sunday to vote on an economic development package that was a critical part of Team South Carolina's all-in effort to land this new Volvo plant, which represents an initial \$500 million investment and 2,000 jobs, both of which could double.

Land it we did, thanks to the leadership of South Carolina Gov. Nikki Haley, Commerce Secretary Bobby Hitt, the South Carolina Power Team, Edisto and Berkeley electric cooperatives, and many other elected officials and agency leaders who pulled together in a tight race for Volvo's first U.S. automobile manufacturing plant. Santee Cooper's role in this deal was to work with Berkeley County and purchase a 6,800-acre tract of land where Volvo is now building the plant. Our Board also approved loans and grants from our existing economic development programs, and Santee Cooper will generate the electricity that Edisto Electric Cooperative distributes to the plant site.

As if all this weren't enough good news, Volvo is only using part of that 6,800-acre tract. Santee Cooper is working with the Power Team and our electric cooperative partners, alongside other state leaders, to recruit additional suppliers and manufacturers to develop and populate a first-rate industrial park on the remaining land. Electric service throughout the park will be transmitted from Santee Cooper generating stations and delivered by Edisto Electric, Berkeley Electric Cooperative and Santee Cooper, meaning that those incentives approved in the historic Mother's Day board meeting are an investment that will benefit all of Santee Cooper customers for decades to come.

Meanwhile, Santee Cooper's loan and grant programs continued to help other partners across the state in local governments and nonprofit economic development corporations. Together, we are continuing to help build out industrial speculative buildings and other infrastructure to attract industry, provide jobs and improve our state's

economy. Santee Cooper will power all of these projects, either directly or through the cooperatives and other wholesale customers, and so they also make good sense for our system and existing customers.

A big part of that power in the future will come from two new units we are building with partner South Carolina Electric and Gas Co. (SCE&G) at V.C. Summer Nuclear Station, the site of the existing nuclear unit we share with SCE&G. We contracted in 2008 with Westinghouse to build two AP1000 nuclear power units, which are scheduled to be online in 2019 and 2020. Nuclear power is reliable and emissions-free, and the new units are a big part of our plan to comply with new Environmental Protection Agency regulations restricting carbon dioxide emissions.

In October, we agreed to changes in our agreement with Westinghouse, which acquired assets of a second partner in the construction consortium and now has more control over the project. The amended agreement also gives Santee Cooper and SCE&G more certainty on price and schedule going forward. This is good news for us and for our customers.

Turning to rates, we approved a two-year rate adjustment that will increase costs to residential, commercial and industrial customers an average of 3.75 percent each of those two years. Employee efforts to keep costs down helped us put off this rate increase; our last adjustment was in 2013, and this new one takes effect in April 2016. A major driver for the rate increase is our nuclear project. Remember, though, nuclear power features low fuel and operating costs once it is built.

Santee Cooper continues to be regarded favorably by bond investors, with successful bond sales in 2015 totaling \$1.4 billion and credit rating agencies holding steady on our ratings. Some \$1.1 billion in bonds were authorized in February, nearly half of that as refunding bonds providing net present value savings of \$58.8 million over the life of the bonds. We issued another \$300.0 million in revenue bonds in December. Proceeds from these sales are primarily being used to finance the nuclear construction project.

In other generation news for 2015, Santee Cooper retired our final two fossil units at Jefferies Generating Station, for a total of six fossil units (two oil, four coal) that we have retired because retrofitting them for new regulations was cost prohibitive. The Jefferies Hydroelectric Station, Santee Cooper's original generating facility, will continue to operate.

Related to the 2012 closing of Jefferies and Grainger generating station coal units is the ongoing excavation of our ash ponds, at both of those stations and also at Winyah Generating Station. Our ash pond excavation has gained national attention as an innovative approach to closing ash ponds and using (recycling) the ash for beneficial purposes. We are delivering this ash to cement and concrete product companies, so with this program we are eliminating an environmental concern, providing a raw material that sustains jobs and the economy, and doing so in a way that is cost-effective for our customers. We beneficially used 531,706 tons of pond ash in 2015.

Increasing our nuclear capacity and reducing our fossil generation are two parts of Santee Cooper's ongoing fuel diversification. Renewable generation is another component, and our signature Green Power program saw a major milestone last year: generation of its 1 millionth megawatt-hour, on Aug. 25. Santee Cooper was the first utility in South Carolina to generate renewable energy for our customers in 2001, when we opened the Horry County Landfill Generating Station. Santee Cooper Green Power is produced from South Carolina resources that meet strict national consumer and environmental standards, and our customers can voluntarily purchase Green Power for their homes and businesses. Santee Cooper then reinvests all Green Power sales revenue into new renewable energy projects.

In October, the Board of Directors approved \$1.7 million in incentives to increase solar power on our system. These incentives, largely rebates, will be used to help our customers install solar panels on their homes or businesses or to buy into our new community solar project at the Colleton Solar Farm, which we believe to be the state's first community solar project. Community solar gives customers the ability to invest in solar power even if

they can't install panels on their own home or business: they can invest in a community solar project and use capacity from that to offset their energy consumption.

Solar power wasn't available to help us meet a new peak electrical demand record on the morning of Feb. 20, however. The new peak demand record of 5,869 MW was set between 7-8 a.m., before the sun was high enough to fuel most solar panels. That is the inherent problem with solar power: It requires backup generation from Santee Cooper when panels aren't producing to meet demand. Storage for renewable generation remains a challenge for utilities and customers alike.

Mother Nature created a bigger challenge as fall set in, with record flooding across South Carolina in October and a continued abundance of rain in November and December. Santee Cooper opened our spillway gates for several days in October, again in November, and on Christmas Day for a prolonged spill of more than three weeks. Spilling is a normal part of hydroelectric operations, although the 2015 spills were larger and longer in duration than in recent history. Santee Cooper's dams and dikes remained safe and secure throughout each of these spilling periods.

Santee Cooper is a state-created electric and water utility charged with being the state's leading resource to improve the quality of life for all South Carolinians. We look back on 2015 as a year full of achievements and initiatives that make this mission possible.

As we look to the future, Santee Cooper will continue to emphasize sound business practices that will keep us lean and agile. Agility is one reason we have been so successful in the bond market – we can respond quickly to opportunity. As we continue to diversify in generation, we will look for opportunities to add practical renewable generation and grow our customer base to benefit all of our customers. We will continue to deliver on our responsibility to provide low-cost, reliable electricity that promotes economic development, and to do so with excellent customer service.



W. Leighton Lord III
Chairman



Lonnie N. Carter
President and CEO

CORPORATE STATISTICS

System Data 2015

Miles of transmission system lines: **5,029**

Miles of distribution system lines: **2,841**

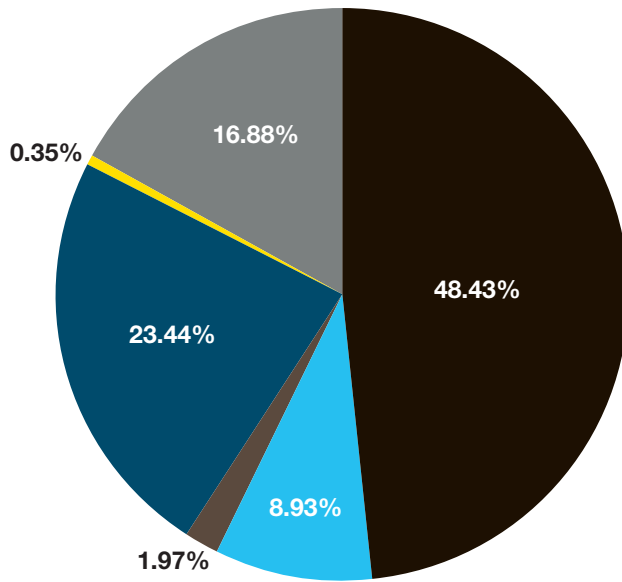
Number of transmission substations: **105**

Number of distribution substations: **54**

Number of CEPCI Delivery Points (DPs): **417**

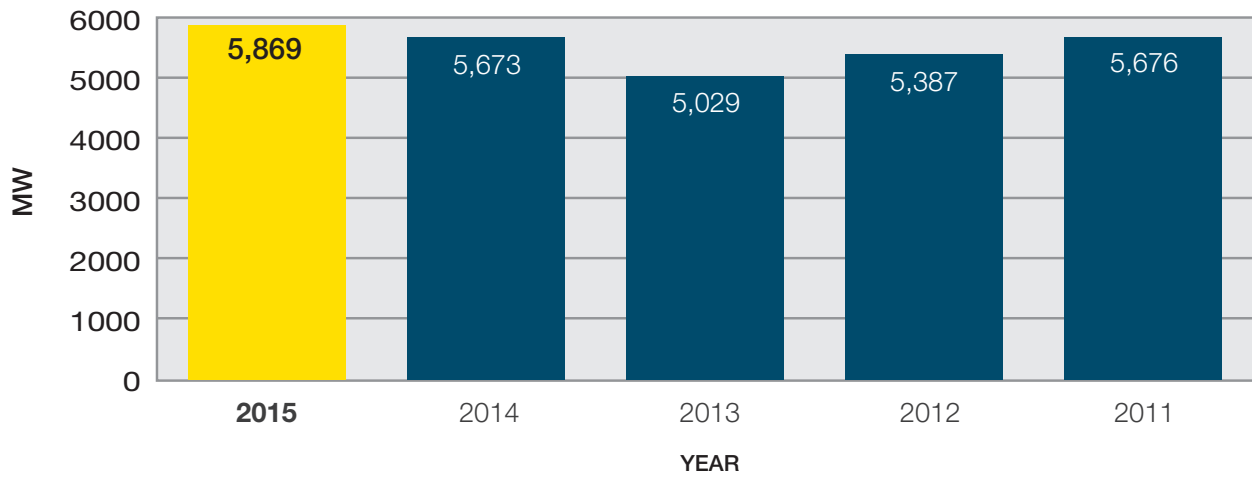
	2015	2014	2013	2012	2011
FINANCIAL (Thousands)					
Total Revenues & Income	\$1,842,541	\$2,023,414	\$1,823,502	\$1,897,135	\$1,923,828
Total Expenses & Interest Charges	1,781,591	1,894,217	1,744,960	1,801,813	1,778,892
Other	(6,435)	19,798	7,396	9,155	5,987
Reinvested Earnings	54,515	148,995	85,938	104,477	150,923
OTHER FINANCIAL (Excluding CP and Other)					
Debt Service Coverage (prior to Distribution to State)	1.45	1.53	1.52	1.44	1.61
Debt / Equity Ratio	78/22	75/25	75/25	73/27	73/27
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	174,023	171,567	168,813	166,809	164,647
Military and Large Industrial	27	28	29	29	29
Wholesale	4	4	4	4	4
Total Customers	174,054	171,599	168,846	166,842	164,680
Generation (GWh):					
Coal	12,832	16,607	13,949	15,888	20,048
Nuclear	2,366	2,297	2,788	2,421	2,469
Hydro	523	506	624	271	274
Natural Gas and Oil	6,212	3,821	4,315	4,710	3,817
Landfill Gas and Renewables	93	96	115	103	115
Total Generation (GWh)	22,026	23,327	21,791	23,393	26,723
Purchases, Net Interchanges, etc. (GWh)	4,987	4,738	5,335	4,099	1,546
Wheeling, Interdepartmental, and Losses	(515)	(712)	(762)	(736)	(717)
Total Energy Sales (GWh)	26,498	27,353	26,364	26,756	27,552
Summer Maximum Continuous Rating (MCR) Generating Capability (MW)	5,093	5,182	5,183	5,665	5,665
Territorial Peak Demand (MW)	5,869	5,673	5,029	5,387	5,676

2015 GENERATION BY FUEL MIX

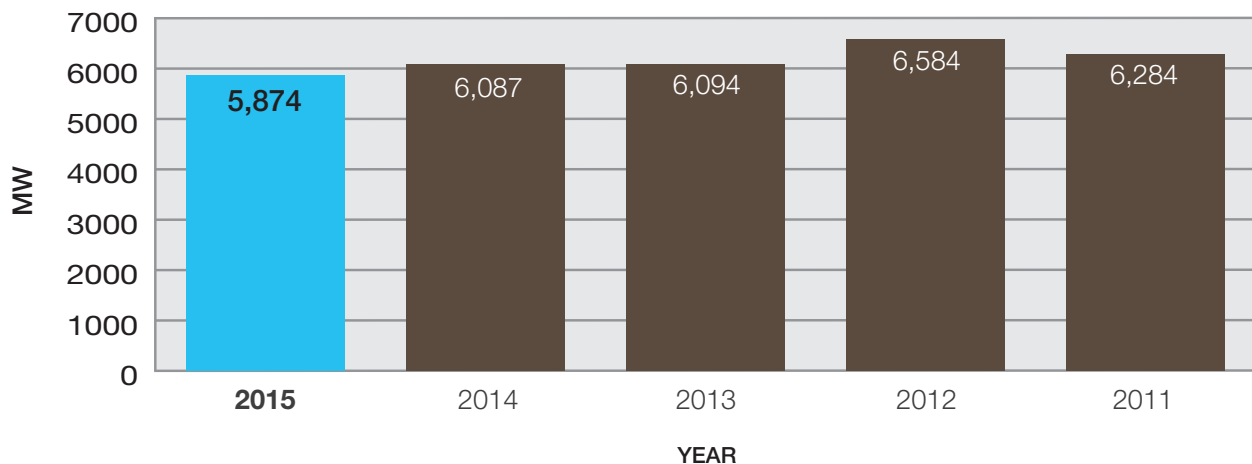


Source		GWh
Coal	48.43%	12,832
Nuclear	8.93%	2,366
Hydro	1.97%	523
Natural Gas & Oil	23.44%	6,212
Other Renewables	0.35%	93
Purchases (Net)	16.88%	4,472
	100.00%	26,498

PEAK DEMAND



TOTAL SUMMER CAPABILITY (MCR) WITH FIRM PURCHASES



AUDIT COMMITTEE CHAIRWOMAN'S LETTER

The Audit Committee of the Board of Directors is comprised of independent directors Peggy H. Pinnell – Chairwoman, William A. Finn, Merrell W. Floyd, Dan J. Ray, Alfred L. Reid Jr. and Jack F. Wolfe Jr.

The committee receives regular reports from members of management and Internal Audit regarding their activities and responsibilities.

The Audit Committee oversees Santee Cooper's financial reporting, internal controls and audit process on behalf of the Board of Directors.

Periodic financial statements and reports pertaining to operations and representations were received from management and the internal auditors. In fulfilling its responsibilities, the committee also reviewed the overall scope and specific plans for the respective audits by the internal auditors and the independent public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

A handwritten signature in black ink, appearing to read "Peggy H. Pinnell". The signature is fluid and cursive, with the first name "Peggy" being more prominent.

Peggy H. Pinnell

Chairwoman

2015 Audit Committee

Notes:

Director Catherine E. Heigel resigned her at-large seat on June 4, 2015. Director Alfred L. Reid Jr. was appointed to the board on June 4, 2015, and rotated onto the committee at that time.

MANAGEMENT'S DISCUSSION AND ANALYSIS

of Financial Condition and Results of Operations

INTRODUCTION

The South Carolina Public Service Authority (the Authority or Santee Cooper) is a component unit of the State of South Carolina (the State), created by the State in 1934 for the purpose of providing and aiding interstate commerce, navigation, electric power and wholesale water to the people of South Carolina. The statute under which it was created provides that the Authority will establish rates and charges so as to produce revenues sufficient to provide for payment of all expenses, the conservation, maintenance and operation of its facilities and properties and the payment of the principal and interest on its notes, bonds, or other obligations. Provided, however, that prior to putting into effect any increase in rates the Authority shall give at least a sixty day notice of such increase to all customers who will be affected.

The Authority's assets include wholly owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill and solar generating units totaling 5,093 megawatts (MW) of summer power supply peak capability. This consists of 3,500 MW of coal-fired capacity, 1,117 MW of natural gas and oil capacity, 318 MW of nuclear capacity, 129 MW of hydro capacity and 29 MW of landfill methane gas capacity. In addition, the Authority may purchase from, sell to or exchange with other bulk electric suppliers additional capacity and energy in order to maximize the efficient use of generating resources, reduce operating costs and increase operating revenues.

The Authority and South Carolina Electric & Gas (SCE&G) are parties to a joint ownership agreement to own and operate the Virgil C. Summer Nuclear Plant (Summer Nuclear) Unit 1 with undivided interests of 33 1/3 and 66 2/3 percent, respectively. In order to further diversify its fuel mix, the Authority has an ownership interest in two 1,117 MW, net nuclear generating units under construction at Summer Nuclear. The Authority also operates an integrated transmission system which includes lines owned by the Authority as well as those owned by Central Electric Power Cooperative (Central), the Authority's largest cost of service customer.

Questions concerning any of the information provided in this report or requests for additional information should be addressed to Glenda Gillette, Vice President and Controller, South Carolina Public Service Authority, P.O. Box 2946101, Moncks Corner, SC 29461-6106.

OVERVIEW OF THE COMBINED FINANCIAL STATEMENTS

This discussion serves as an introduction to the basic combined financial statements of the Authority to provide the reader with an overview of the Authority's financial position and operations. As discussed in the notes to the Combined Financial Statements (Note 1 - B "System of Accounts"), the combined financial statements include the accounts of the Lake Moultrie Water Agency and Lake Marion Regional Water Agency.

The Combined Statements of Net Position summarize information on the Authority's assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position.

The operating results of the Authority are presented in the Combined Statements of Revenues, Expenses and Changes in Net Position. Revenues represent billings for electricity sold and fuel expense (see Note 1 - O, "Revenue Recognition and Fuel Costs"), as well as wholesale water sales. Expenses primarily include operating costs and debt service related charges.

The Combined Statements of Cash Flows are presented using the direct method. This method provides broad categories of cash receipts and cash disbursements related to cash provided by or used in operations, non-capital related financing, capital related financing and investing activities.

The Notes are an integral part of the Authority's basic combined financial statements and provide additional information on certain components of these statements.

FINANCIAL CONDITION OVERVIEW

The Authority's Combined Statements of Net Position as of December 31, 2015, 2014 and 2013 are summarized below:

	2015	2014	2013
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	\$ 7,509,121	\$ 6,917,786	\$ 6,375,051
Current assets	3,155,271	2,837,902	2,808,713
Other noncurrent assets	1,329,395	1,248,905	1,384,597
Deferred outflows of resources	256,734	203,638	139,235
Total assets & deferred outflows of resources	\$ 12,250,521	\$ 11,208,231	\$ 10,707,596
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	\$ 7,306,469	\$ 6,639,162	\$ 6,456,379
Current liabilities	1,299,591	1,031,382	892,044
Other noncurrent liabilities	1,469,189	1,160,723	1,125,051
Deferred inflows of resources	233,482	208,501	193,995
Total liabilities & deferred inflows of resources	\$ 10,308,731	\$ 9,039,768	\$ 8,667,469
NET POSITION			
Net invested in capital assets	\$ 1,195,402	\$ 957,835	\$ 895,969
Restricted for debt service	79,771	108,457	92,662
Restricted for capital projects	4,304	6,515	0
Unrestricted	662,313	1,095,656	1,051,496
Total net position	\$ 1,941,790	\$ 2,168,463	\$ 2,040,127
Total liabilities, deferred inflows of resources & net position	\$ 12,250,521	\$ 11,208,231	\$ 10,707,596

2015 COMPARED TO 2014

The primary changes in the Authority's combined financial condition as of December 31, 2015 and 2014 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources increased \$1,042.3 million during 2015 due to increases of \$591.3 million in capital assets, \$317.4 million in current assets, \$80.5 million in other noncurrent assets and \$53.1 million in deferred outflows of resources.

The increase in capital assets of \$591.3 million was due to net construction work in progress increases of \$624.5 million partially offset by a net decrease in utility plant and other physical property of \$33.2 million. The increase resulted primarily from additions associated with Summer Nuclear Units 2 and 3, which are not currently in service.

The increase in current assets of \$317.4 million was due to net additions of \$209.4 million in restricted cash, cash equivalents and investments resulting from the 2015 bond activity impact, construction payments and debt service payments. Fossil fuel inventory increased \$174.1 million due to increased coal purchases in 2015 to take advantage of spot market pricing combined with a reduction in coal generation this year. Prepaid expenses and other current assets decreased \$32.7 million primarily due to the current year amortization of a portion of the remaining balance of assets from a cancelled coal-fired generation project in Florence County, S.C. Nuclear fuel inventory increased \$11.4 million due to additional purchases of fuel. The remaining \$44.8 million was a decrease resulting from the net change in unrestricted cash, cash equivalents, investments, receivables, materials inventory and interest receivable.

The increase in other noncurrent assets of \$80.5 million resulted from \$23.5 million additions of new economic development loans and \$18.5 million in deferred interest from the sale of five percent of the Summer Nuclear Units 2 & 3. Further increases of \$39.6 million were provided by the asset retirement obligation due to accretion and depreciation on nuclear and ash pond assets. Other items with a net decrease of \$1.1 million are due to the residual changes in the other accounts in this category.

The increase in deferred outflows of resources of \$53.1 million was largely due to the Authority reporting \$31.4 million of its share of pension deferrals associated with the 2015 GASB 68 implementation, as well as an accumulated decrease in fair value of hedging derivatives of \$21.4 million. The higher reduction in accumulated decrease in fair value of hedging derivatives was due to increased mark-to-market losses driven by lower natural gas prices during 2015. Further increases were provided by higher unamortized loss on refunded and defeased debt of \$0.3 million.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources increased \$1,269.0 million due to increases of \$667.3 million in long-term debt-net, \$268.2 million in current liabilities, \$308.5 million in other noncurrent liabilities and \$25.0 million in deferred inflows of resources.

Net long-term debt increased \$667.3 million due mainly to net additions of \$561.9 million in total long-term debt and \$105.4 million in unamortized debt discounts and premiums. The increase in long-term debt was mainly due to additions of \$1,442.9 million from the 2015 bond activity. Offsetting this was a decrease of \$262.5 million for transfers to current portion of long-term debt, \$44.9 million for transfers from other long-term obligations to a current liability and \$573.6 million due to defeasance and/or refunding activity. Unamortized debt discounts and premiums increased due to net additions of \$143.5 million from the 2015 bond activity. Offsetting this were decreases of \$27.9 million for amortization of discounts and premiums and \$10.2 million for removals from refunding bond activity.

The increase in current liabilities of \$268.2 million was due to \$187.4 million for commercial paper and \$102.0 million for additional accruals primarily associated with Summer Nuclear Units 2 and 3 construction and other generating station outages. Additional changes were caused by increases in the current portion of long-term debt of \$23.2 million and a reduction in accrued interest on long-term debt of \$11.7 million. Further reductions of \$32.7 million were provided mainly by the Central Cost of Service (COS) adjustment between the periods.

Other noncurrent liabilities increased \$308.5 million primarily from booking a net pension liability of \$286.3 million associated with the 2015 implementation of GASB 68. Further increases were due to higher gas hedging transactions of \$21.5 million as well as changes in the asset retirement obligation liability of \$2.4 million due to accretion on nuclear and ash pond liabilities. Net decreases of \$1.7 million among the remaining accounts make up the residual variance.

Deferred inflows of resources increased \$25.0 million mainly due to booking pension deferrals of \$17.4 million associated with the 2015 GASB 68 implementation. Further increases were provided by the accumulated increase in fair value of hedging derivatives of \$3.6 million as well as higher nuclear decommissioning costs of \$4.0 million resulting from market value adjustments, amortization and interest accruals for decommissioning funds.

The decrease in net position of \$226.7 million was mainly due to a reduction in unrestricted of \$433.3 million from a prior period adjustment of \$261.1 million associated with the 2015 GASB 68 implementation. The increase in net invested capital assets of \$237.5 million was due to higher construction work in progress, and utility plant. Restricted for debt service decreased \$28.7 million due to changes in accrued interest on long-term debt and reductions in the bond and debt service funds. A lower amount of non-borrowed funds for the Lake Moultrie Water Agency capacity upgrade of \$2.2 million caused a decrease in restricted for capital projects.

2014 Compared to 2013

The primary changes in the Authority's combined financial condition as of December 31, 2014 and 2013 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources increased \$500.6 million during 2014 due to increases of \$542.7 million in capital assets, \$29.2 million in current assets and \$64.4 million in deferred outflows of resources. Offsetting these increases were reductions in other noncurrent assets of \$135.7 million.

The increase in capital assets was due to net construction work in progress and utility plant increases of \$612.2 million and \$156.4 million, respectively. These increases resulted from construction costs associated with Summer Nuclear Units 2 and 3 as well as construction projects at several generating facilities and on the transmission system. Offsetting these increases were retirements of \$43.6 million. Further reductions were caused by accumulated depreciation increasing \$182.1 million and a small reduction in other physical property.

The increase in current assets was due primarily to net additions of \$180.1 million in restricted cash, cash equivalents and investments resulting from the 2014 bond activity impact, construction payments and debt service payments. Fossil fuel inventory decreased \$113.4 million due to increased fossil generation and delays in coal transportation. Nuclear fuel inventory decreased \$12.6 million due to amortization expense for fuel burned at Summer Nuclear Unit 1. The remaining \$24.9 million was a decrease resulting from the net change in unrestricted cash, cash equivalents, investments, receivables, materials inventory, interest receivable and prepaid expenses and other current assets.

The decrease in other noncurrent assets was due to a reduction in other noncurrent and regulatory assets resulting from the receipt of \$231.9 million from the Santee River Flooding case settlement. Further reductions resulted from a change in deferred interest receivable of \$13.5 million related to the sale of five percent of Summer Nuclear Units 2 and 3. Offsetting these reductions was \$7.9 million in net additions related to the transfer of Pee Dee costs as well as \$8.4 million more in billable projects. The asset retirement obligation increased \$56.5 million due to accretion and depreciation on nuclear and ash pond assets. Restricted cash, cash equivalents and investments rose \$12.4 million resulting from investment income and market value adjustments. Further increases were provided by higher costs to be recovered from future revenues (CTBR) of \$19.8 million from the 2014 bond activity and lower depreciation rates. The remaining variance was due to changes in the other accounts in this category.

The increase in deferred outflows of resources was due to a larger accumulated decrease in fair value of hedging derivatives and higher unamortized loss on refunded and defeased debt of \$50.6 million and \$13.8 million, respectively. The higher reduction in accumulated decrease in fair value of hedging derivatives was due to increased mark-to-market losses driven by lower natural gas prices during 2014. The larger unamortized loss on refunded and defeased debt was due to amortization, additions and removals from current year bond activity.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources increased \$372.3 million due to increases of \$182.8 million in long-term debt-net, \$139.3 million in current liabilities, \$35.7 million in other noncurrent liabilities and \$14.5 million in deferred inflows of resources.

Long-term debt-net increased \$182.8 million due to net additions of \$85.6 million in total long-term debt and \$97.2 million in unamortized debt discounts and premiums. The increase in long-term debt was due to additions of \$1,420.9 million from the 2014 bond activity. Offsetting this was a decrease of \$556.1 million for transfers to current portion of long-term debt and \$779.2 million due to defeasance or refunding activity. Unamortized debt discounts and premiums increased due to net additions of \$144.1 million from the 2014 bond activity. Offsetting this were decreases of \$22.0 million for amortization of discounts and premiums and \$24.9 million for removals from refunding bond activity.

The increase in current liabilities was due to \$38.1 million for commercial paper, \$36.8 million for natural gas hedging losses, additional manual accruals for Summer Nuclear Units 2 and 3 construction, Summer Nuclear Unit 1 fuel and other generating station outages of \$42.1 million as well as a \$26.5 million higher Central COS adjustment between the periods. Additional changes were caused by increases in the current portion of long-term debt of \$16.0 million and a reduction in accrued interest on long-term debt of \$21.1 million. Other smaller changes resulted in the residual variance.

Other noncurrent liabilities increased due to changes in the asset retirement obligation liability of \$19.4 million due to accretion on nuclear and ash pond liabilities, as well as net noncurrent hedging losses of \$11.7 million. Increases were also noted in Summer Nuclear pension and other post-employment benefits (OPEB) liabilities of \$3.6 million, construction liabilities of \$2.8 million, as well as deferred emission credit sales of \$2.5 million. These increases were offset by a decrease in the noncurrent liability of \$6.2 million for a maintenance agreement for the Rainey Generating Station. Net increases among the remaining accounts make up the residual variance.

Deferred inflows of resources increased due to higher nuclear decommissioning costs of \$21.5 million resulting from market value adjustments, amortization and interest accruals for decommissioning funds. Offsetting this increase was \$7.0 million reduction in accumulated increase in fair value of hedging derivatives caused by differing market conditions between the periods.

The main drivers for the overall increase in net position were higher net invested in capital assets and unrestricted of \$61.9 million and \$44.2 million, respectively. The increase in net invested in capital assets was due to higher construction work in progress, utility plant and the asset retirement obligation. Offsetting this increase was higher long-term debt and accumulated depreciation. Restricted for debt service also increased \$15.8 million due to changes in accrued interest on long-term debt and reductions in the bond and debt service funds. An addition of non-borrowed funds for the Lake Moultrie Water Agency capacity upgrade of \$6.5 million caused an increase in restricted for capital projects.

RESULTS OF OPERATIONS

Santee Cooper's Combined Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2015, 2014 and 2013 are summarized as follows:

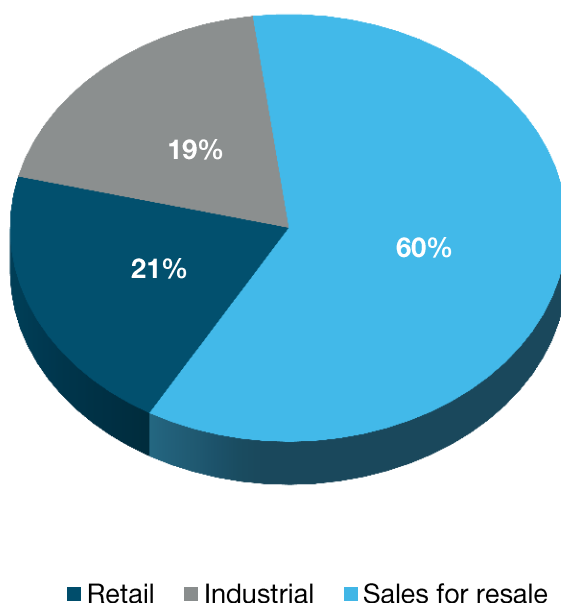
	2015	2014	2013
	(Thousands)		
Operating revenues	\$ 1,879,553	\$ 1,997,347	\$ 1,816,576
Operating expenses	1,502,488	1,619,224	1,524,182
Operating income	377,065	378,123	292,394
Interest expense	(279,103)	(274,993)	(220,778)
Costs to be recovered from future revenue	(6,435)	19,798	7,396
Other income	(37,012)	26,067	6,926
Capital contributions & transfers	(20,116)	(20,659)	(20,394)
Change in net position	\$ 34,399	\$ 128,336	\$ 65,544
Net position - beginning of period as previously reported	2,168,463	2,040,127	1,974,583
Restatement (Note 15)	(261,072)	0	0
Net position - beginning of period as restated	1,907,391	2,040,127	1,974,583
Ending net position	\$ 1,941,790	\$ 2,168,463	\$ 2,040,127

2015 Compared to 2014

OPERATING REVENUES

As compared to 2014, operating revenues decreased \$117.8 million (6%). The driver for this decrease was lower kWh sales (3%) and demand usage (2%). Partially offsetting this decrease was higher O&M rate revenues, energy related fixed cost rates and impacts between the 2014 and 2015 Central COS adjustments. Energy sales for 2015 totaled approximately 26.5 million megawatt hours (MWhs) as compared to approximately 27.4 million MWhs for 2014.

**2015 Revenues from Sales of Electricity*
by Customer Class**



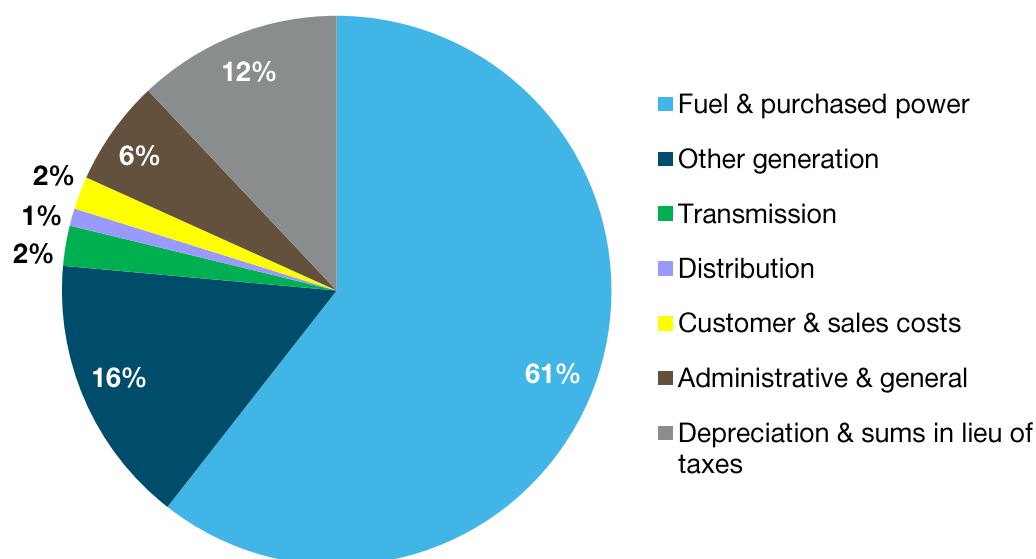
	2015	2014	2013
Revenues from Sales of Electricity*		(Thousands)	
Retail	\$ 381,049	\$ 394,195	\$ 355,598
Industrial	354,148	399,817	381,689
Sales for resale	1,121,326	1,181,350	1,058,943
Totals	\$ 1,856,523	\$ 1,975,362	\$ 1,796,230

*Excludes interdepartmental sales of \$478 for 2015, \$488 for 2014 and \$442 for 2013.

OPERATING EXPENSES

Combined operating expenses for 2015 decreased \$116.7 million (7%) as compared to 2014. The main driver was fuel and purchased power expense which decreased by \$151.0 million due to lower kWh sales, higher commodity prices in the prior year and a shift in generation mix. Partially offsetting these decreases were higher non-fuel generation (\$27.6 million) from labor, contract services, materials and Summer Nuclear Unit 1 expenses as well as transmission (\$2.4 million) from a self-insurance claim, labor, benefits, contract services and lower New Horizon Electric Cooperative reimbursements. Other smaller variances (\$4.3 million) netted an increase and were spread among the remaining cost categories.

**2015 Electric Operating Expenses
by Category**



	2015	2014	2013
Electric Operating Expenses		(Thousands)	
Fuel & purchased power	\$ 906,954	\$ 1,057,907	\$ 958,566
Other generation	237,680	210,083	195,788
Transmission	35,425	32,998	32,211
Distribution	15,340	14,503	14,439
Customer & sales costs	28,792	27,994	21,672
Administrative & general	93,171	92,967	95,839
Depreciation & sums in lieu of taxes	180,167	178,037	201,143
Totals	\$ 1,497,529	\$ 1,614,489	\$ 1,519,658

NET BELOW THE LINE ITEMS

- Other income decreased by \$63.1 million due to the current year amortization of the remaining balance of assets from a cancelled coal-fired generation project in Florence County, S.C., reclassification of the Duke Energy good faith deposit in the prior year and higher interest income in the prior year from the Santee River case settlement.
- Interest expense for 2015 was \$4.1 million higher as a result of the 2015 bond activity.
- CTBR changed \$26.2 million due to implementation of a new methodology, effective January 1, 2015.
- Capital contributions and transfers represent dollars paid to the state of South Carolina. This payment decreased by \$0.5 million and it was based on a percentage of total budgeted revenues which was lower in the 2015 budget compared to the 2014 budget.

2014 Compared to 2013*OPERATING REVENUES*

As compared to 2013, operating revenues increased \$180.8 million (10%). The driver for this increase was higher kWh sales (4%) and demand usage (5%). Partially offsetting this increase was lower demand and O&M rate revenues. Energy sales for 2014 totaled approximately 27.4 MWhs compared to approximately 26.4 million MWhs for 2013 with increases in all categories except industrial.

OPERATING EXPENSES

Combined operating expenses for 2014 increased \$95.0 million (6%) as compared to 2013. Fuel and purchased power increased by \$99.3 million due to higher kWh sales associated with weather impacts, along with a shift in the economic dispatch due to station outages and higher prices in the energy markets. Non-fuel generation was higher by \$14.3 million from expenses related to contract services, materials and Summer Nuclear Unit 1 expenses, as well as customer and sales promotion being up by \$6.3 million as a result of the accrual of economic development grants. Offsetting these increases was a decrease in administrative and general of \$2.9 million resulting from contract services and insurance expense. Depreciation expense also decreased by \$23.1 million from catch-up depreciation recorded in 2013 and the impact of the new depreciation rates implemented in 2014. The remaining variance was attributable to the net of the remaining categories being higher than prior year.

NET BELOW THE LINE ITEMS

- Other income increased by \$19.1 million over 2013 from interest received on the Santee River Flooding case settlement.
- Interest expense for 2014 was \$54.2 million higher than 2013 resulting from the 2013 and 2014 bond activity impacts.
- CTBR changed \$12.4 million due to a combination of bond activity and lower depreciation rates.
- The \$265,000 increase in capital contributions & transfers represents dollars paid to the State. This payment is based on a percentage of total budgeted revenues which was higher in the 2014 budget compared to the 2013 budget.

ECONOMIC CONDITIONS

The Authority and the electric industry continue to face economic and industry challenges that impact the competitiveness and financial condition of the utility. As market conditions fluctuate, the Authority's mission is to deliver low-cost and reliable electricity and water to its customers.

To address these challenges, the Authority has developed business growth initiatives that revolve around four strategic initiatives - marketing, product development, project management and competitive rates. The Authority is marketing industrial and commercial properties that are served directly by the Authority and its Electric Cooperative partners and municipal customers. Product development activities include the creation and/or improvement of industrial properties, the acquisition of property, expansion of infrastructure into industrial properties, and/or constructing buildings for industrial uses. Since June 2012, the Authority has invested over \$50.0 million throughout South Carolina in product development through low-interest revolving loans to public entities. During 2014, the Authority created two additional funds for the purpose of providing potential industrial sites in Cooperative and municipal territories, directly or indirectly served by Santee Cooper. Approvals through 2015 total more than \$4.0 million from the municipal site readiness fund and over \$9.0 million from the South Carolina Power Team Site Readiness Fund. The Authority continues to offer an economic development rate, the Experimental Large Light and Power Economic Development Service Tiered Rider, in addition to its existing economic development rider. Both rates are targeted at attracting new and expanding industrial loads and are available to the Authority's direct served industrial loads and are to be passed through to the Authority's wholesale customers located in South Carolina.

The Authority's largest customer is Central and accounted for 57.6 percent of sales revenues. Central provides wholesale electric service to each of the 20 distribution cooperatives (Central Cooperatives) which are members of Central pursuant to long-term all requirements power supply agreements. In September 2009 Central and the Authority entered into an agreement (September 2009 Agreement) that, among other things, provides for Central to transition a portion of the power and energy requirements of the five former Saluda members (Upstate Load) directly connected to the transmission system of Duke Energy Carolinas, LLC (Duke Energy) to another supplier and in January 2013, Central began transitioning the Upstate Load to Duke Energy. The September 2009 Agreement provides for approximately 15 percent of the Upstate Load to transition to Duke Energy annually between 2013 – 2018, with the remaining 10 percent of the Upstate Load transitioning to Duke Energy in 2019. By the end of the transition in 2019 the Upstate Load transferred will amount to approximately 900 MW. Nothing would preclude the Authority from serving this load when the Duke Energy agreement ends on December 31, 2030.

The Authority and Central continue to work cooperatively to better align their future interests and formalize how they will jointly plan for new resources. As part of this, Central agreed to extend their rights to terminate the agreement in the September 2009 Agreement until December 31, 2058. Under the Central Agreement 10-year rolling notice provision, for a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. Central has entered into requirement agreements with all 20 of its member cooperatives that extend through December 31, 2058 and obligate those members to pay their share of Central's costs, including costs paid under the Central Agreement. This amendment also provides more stability and certainty to the credit agencies as they rate the Authority's bonds going forward.

CAPITAL IMPROVEMENT PROGRAM

The purpose of the capital improvement program is to continue to meet the energy and water needs of the Authority's customers with economical and reliable service. The Authority's three-year budget for the capital improvement program approved in 2015, 2014 and 2013 was as follows:

	2015 Budget 2016-18	2014 Budget 2015-17	2013 Budget 2014-16
Capital Improvement Expenditures		(Thousands)	
Environmental compliance	\$ 318,972	\$ 154,939	\$ 179,394
General improvements to the system	698,773	566,761	535,832
Summer Nuclear Units 2 and 3	1,693,252	1,677,228	1,737,609
Totals	\$ 2,710,997	\$ 2,398,928	\$ 2,452,835

As determined by the Authority, the cost of the capital improvement program will be provided from revenues, additional revenue obligations, commercial paper and other short-term obligations.

Summer Nuclear Units 2 and 3

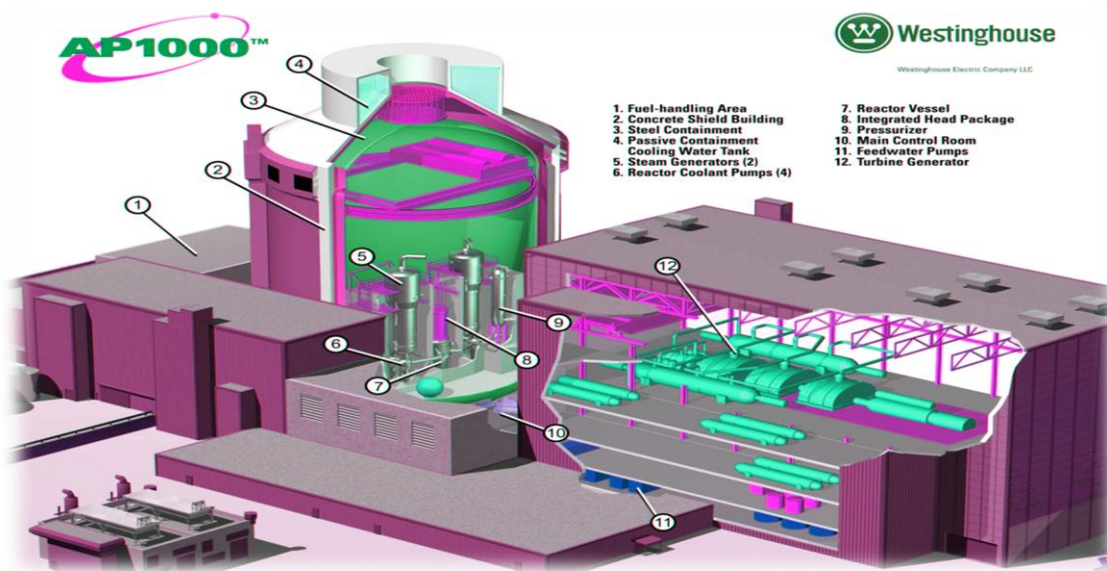


Technology - Summer Nuclear Units 2 and 3 will consist of two Westinghouse AP1000 nuclear reactors, four low profile sixteen-cell mechanical draft cooling towers, intake and discharge structures, a 230 kV switchyard for transmission access, and numerous ancillary structures supporting the power generation process.

On January 27, 2006, the NRC approved the AP1000 standard plant design and issued its original AP1000 Design Certification Rule (DCR) which incorporated Revision 15 of the AP1000 Design Control Document (DCD).

On December 30, 2011, the NRC amended its regulations to certify an amendment to the AP1000 standard plant design incorporated in DCD Revisions 16 through 19. The amendment replaces the combined license information items and design acceptance criteria (DAC) with specific design information, addresses the effects of the impact of a large commercial aircraft, incorporates design improvements, and increases standardization of the design.

The AP1000 is the first and only reactor in its class of technological development, referred to as “Generation III+”, to receive certification from the NRC.



The AP1000 is a pressurized water reactor with passive safety systems which, according to Westinghouse, in case of design basis accidents are designed to achieve a safe shutdown without operator action, AC power, or pumps.

Licensing - In March 2008, the Authority and SCE&G submitted to the NRC an application for Combined Construction and Operating Licenses (COLs) for Summer Nuclear Units 2 and 3. On March 30, 2012, the NRC concluded its mandatory hearing process for the application and found the NRC staff's review adequate to make the necessary regulatory safety and environmental findings, clearing the way for the formal issuance of the COLs. The COLs were issued by the NRC and received by SCE&G and the Authority on March 30, 2012.

The NRC's findings concluding the mandatory hearing process imposed two conditions on the COLs, with the first requiring inspection and testing of squib valves, important components of the reactor's passive cooling system. The second requires the development of strategies to respond to extreme natural events resulting in the loss of power at the new reactors. The NRC also directed the Office of New Reactors to issue to SCE&G and the Authority, simultaneously with the COLs, an Order requiring enhanced, reliable spent fuel pool instrumentation, as well as a request for information related to emergency plant staffing.

Engineering, Procurement, and Construction Agreement - On May 23, 2008, SCE&G, acting for itself and as agent for the Authority, entered into an Engineering, Procurement, and Construction (EPC) Agreement, with a Consortium consisting of Westinghouse Electric Company, LLC ("Westinghouse") and Stone & Webster, Inc. Pursuant to the EPC Agreement, the Consortium will supply, construct, test, and start up two 1,117 MW nuclear generating units utilizing Westinghouse's AP1000 standard plant design. Under the EPC Agreement, the Authority will pay, in proportion to its ownership interest, a contract price that is subject to certain fixed price escalations and adjustments, adjustments for change orders and performance bonuses, and adjustments for cost overruns. A majority of the EPC Agreement costs are fixed or firm. In addition to EPC Agreement costs, the Authority will pay, in proportion to its ownership interest, costs associated with ancillary project facilities, staffing, project management and oversight by SCE&G and the Authority. The Authority estimates the current total construction cost associated with a 45 percent ownership interest to be approximately \$5.1 billion including related transmission and initial nuclear fuel cores.

The EPC Agreement provides the Authority and SCE&G are jointly and severally liable for obligations under the EPC Agreement, to the extent such joint and several liability does not conflict with State law applicable to the Authority. Current State law provides the Authority shall be severally liable, in proportion to its joint ownership interest, for the acts, omissions, obligations performed, omitted, or incurred by SCE&G acting as agent for the Authority in constructing, operating or maintaining the Summer Units, but is not otherwise liable, jointly or severally for SCE&G's acts or omissions.

The EPC Agreement provides for certain liquidated damages upon the Consortium's failure to comply with schedule and performance guarantees, as well as certain bonuses payable to the Consortium for unit performance. The Consortium's liability for liquidated damages and for warranty claims is subject to a cap. The payment obligations of Westinghouse are guaranteed by Toshiba Corporation, and the payment obligations of Stone & Webster are guaranteed by Chicago Bridge & Iron Company. The Authority and SCE&G may, at any time, terminate the EPC Agreement for their convenience and without cause, provided that the Authority and SCE&G will pay certain termination costs and, at certain stages of the work, termination fees to the Consortium. The Consortium may terminate the EPC Agreement under certain circumstances, including (i) either SCE&G or the Authority's failure to make payment to Consortium in accordance with the EPC Agreement requirements, (ii) either SCE&G or the Authority's breach of a material provision of the EPC Agreement, or (iii) either SCE&G or the Authority's insolvency unless the other of SCE&G or the Authority has provided security for payments that would be due from such insolvent entity.

Ownership Agreements - On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement specifying an Authority ownership interest of 45 percent in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Among other things, the Design and Construction Agreement allows either or both parties to withdraw from the project under certain circumstances. Also on October 20, 2011, the Authority and SCE&G entered into an Operating and Decommissioning Agreement with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement define the conditions under which the Authority or SCE&G may convey an undivided ownership interest in the units to a third party.

Recent Developments - In January 2014, the Authority entered into an agreement whereby SCE&G will purchase from the Authority an additional five percent interest in the project. Under the terms of the agreement, SCE&G will own 60 percent of the new nuclear units and the Authority, 40 percent. The five percent ownership interest will be acquired in three stages, with one percent to be acquired at the commercial operation date of the first new nuclear unit, an additional two percent to be acquired no later than the first anniversary of such commercial operation date and the final two percent to be acquired no later than the second anniversary of such commercial operation date. The purchase price will be equal to the Authority's actual cost, including financing costs, of the percentage conveyed as of the date of the conveyance. The total purchase price is estimated to be between \$500.0 and \$600.0 million. The agreement will not impact the payment obligation for the full 45 percent ownership during construction. Under the terms of agreement with SCE&G the Authority cannot enter into an agreement to sell an additional portion of its 40 percent ownership interest until both units have been completed. However, the Authority is free to explore power sale opportunities from the facility. In December 2015, the Authority and SCE&G executed the Purchase and Sale Agreement for SCE&G's purchase from the Authority of an additional five percent interest in the project as described above.

Construction - Phase I - Phase I of the work consisted of the Consortium's engineering support and other services required by SCE&G and the Authority to support licensing efforts for Summer Nuclear Units 2 and 3 (including receipt of approvals from the PSC), continuation for design work, project management, engineering and administrative support to procure long lead time equipment, construction mobilization, site preparation, site infrastructure development, and installation of construction facilities. Phase I commenced May 23, 2008, with execution of the EPC Agreement, and was completed April 17, 2012 with SCE&G and the Authority's issuance of Full Notice to Proceed following receipt of the COLs.

Construction - Phase II - Phase II of the work consists of the remainder of the work required to supply, construct, test, and start up two AP1000 nuclear power plant units as is consistent with the AP1000 certified design. Phase II work is progressing and several key construction milestones have been achieved for Summer Nuclear Units 2 and 3.

Unit(s)	Construction Milestone	Date
Units 2 & 3	Energized Switchyard	February 1, 2013
Unit 2	Placed Nuclear Island Basemat (First Nuclear Concrete)	March 11, 2013
Unit 2	Set Module CR10 (Containment Vessel Bottom Head Support)	April 3, 2013
Unit 2	Set Containment Vessel Bottom Head	May 22, 2013
Unit 2	Set Structural Module CA04 (Reactor Vessel Cavity)	September 27, 2013
Unit 3	Placed Nuclear Island Basemat (First Nuclear Concrete)	November 4, 2013
Unit 2	Set Structural Module CA20 (Auxiliary Building Module)	May 9, 2014
Unit 3	Set Containment Vessel Bottom Head	May 21, 2014
Unit 2	Set Containment Vessel Ring 1	June 2, 2014
Unit 2	Set Structural Module CA05	December 6, 2014
Unit 3	Set Structural Module CA04 (Reactor Vessel Cavity)	June 29, 2015
Unit 2	Set Structural Module CA01 (Steam Generator and Refueling Canal)	July 23, 2015

Schedule - During the course of activities under the EPC Agreement, issues have materialized that have impacted project budget and schedule. The parties to the EPC Agreement have established both informal and formal dispute resolution procedures to resolve issues that arise during the course of constructing a project of this magnitude.

Claims specifically relating to COL delays, design modifications of the shield building and certain prefabricated structural modules and unanticipated rock conditions at the site resulted in assertions of contractual entitlement to recover additional costs to be incurred. On July 11, 2012, SCE&G, on behalf of itself and as agent for the Authority, agreed to a settlement with the Consortium which set the Authority's portion of the costs for these specific claims at approximately \$113.0 million (in 2007 dollars). As a result of this settlement, the substantial completion dates for Summer Nuclear Units 2 and 3 changed from April 2016 and January 2019 (respectively) to March 2017 and May 2018.

Subsequent to July 2012, the Consortium has experienced delays in the schedule for fabrication and delivery of sub-modules for the new units. After examination of this issue and consultation with the Consortium, in June 2013, SCE&G announced that the substantial completion of Summer Nuclear Unit 2 was expected to be delayed from March 2017 to late 2017 or the first quarter of 2018 and the substantial completion for Summer Nuclear Unit 3 was expected to be similarly delayed. The dates have not been accepted as revised contractual substantial completion dates.

Since August 2013, the Consortium has experienced additional delays in sub-module fabrication and deliveries. The fabrication and delivery of sub-modules for Summer Nuclear Unit 2 are a focus area of the Consortium, including sub-modules for module CA20, which is part of the auxiliary building, and CA01, which houses components inside the containment vessel. Modules CA20 and CA01 are considered critical path items for both new units. All sub-modules for CA20 have been received on site, assembly completed, and the module placed on the nuclear island in May 2014. The delivery schedule of the sub-modules for CA01 is expected to support completion of on-site fabrication to allow it to be placed on the nuclear island 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 project delays associated with incomplete engineering and late submodule fabrication and deliveries. The result will be a revised fully integrated project schedule.

In early August 2014, SCE&G and the Authority received preliminary schedule information in which the Consortium indicated 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.

Since receiving the August 2014 preliminary schedule information, SCE&G and the Authority received a preliminary cost estimate associated with the schedule delays. The estimate to achieve a late 2018 substantial completion date totaled \$1.176 billion for non-firm and non-fixed scopes of work. In addition to delay-related costs, this figure included project scope modifications currently under review by the Owners. This figure was presented as a total project cost in 2007 dollars subject to escalation and does not reflect consideration of the delay liquidated damages provisions of the EPC agreement which would partly mitigate any such delay-related costs.

SCE&G and the Authority have worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium has indicated that the Unit 2 substantial completion date is expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. SCE&G and the Authority are continuing discussions with Consortium executive management in order to identify potential mitigation strategies to accelerate the substantial completion dates of the units and are working to arrive at an acceptable revised schedule and cost estimate.

On October 27, 2015, the EPC Agreement was amended ("October 2015 Amendment"). The October 2015 Amendment became effective on December 31, 2015 upon the consummation of the acquisition by Westinghouse of the stock of Stone & Webster from CB&I. Stone & Webster will continue to be a member of the Consortium as a subsidiary of Westinghouse instead of CB&I. Westinghouse has engaged Fluor Corporation as a subcontracted construction manager.

Among other things, the October 2015 Amendment (i) resolves by settlement and release substantially all outstanding disputes between SCE&G and the Authority (collectively “Owner”) and the Consortium, in exchange for (a) an additional cost of \$300.0 million (Authority’s 45 percent portion being \$135.0 million) paid by the Owner and an increase in the fixed component of the contract price by that amount, and (b) a credit to Owner of \$50.0 million (Authority’s 45 percent portion being approximately \$23.0 million) applied to the target component of the contract price, (ii) revises the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively, (iii) revises the delay-related liquidated damages computation requirements, including those related to the eligibility of the Units to earn Internal Revenue Code Section 45J production tax credits, and caps those aggregate liquidated damages at \$463.0 million per Unit (Authority’s 45 percent portion being approximately \$208.0 million per Unit), (iv) provides for payment to the Contractor of a completion bonus of \$275.0 million per Unit (Authority’s 45 percent portion being approximately \$124.0 million per Unit) for each Unit placed in service by the deadline to qualify for production tax credits, (v) provides for the development of a revised construction payment milestone schedule, with the Owner making monthly payments of \$100.0 million (Authority’s 45 percent portion being \$45.0 million) for each of the first five months following effectiveness, followed by payments made based on milestones achieved, and (vi) cancels the CB&I Parent Company Guaranty with respect to the Project. The payment obligations under the EPC Agreement are joint and several obligations of Westinghouse and Stone & Webster, and the October 2015 Amendment provides for Toshiba Corporation, Westinghouse’s parent company, to reaffirm its guaranty of Westinghouse’s payment obligations.

In addition to the above, this October 2015 Amendment provides for an explicit definition of a Change in Law designed to reduce the likelihood of certain commercial disputes. As part of this, the Consortium also acknowledges and agrees that the Project scope includes providing the Owner with Units that meet the standards of the NRC approved Design Control Document Revision 19. The October 2015 Amendment also provides for establishment of a dispute resolution board process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction payment milestone schedule referred to above. The EPC Agreement is also revised to eliminate the requirement or ability to bring suit before substantial completion of the Project.

Finally, this October 2015 Amendment provides the Owner an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Agreement to fix the total amount to be paid to the Consortium for its entire scope of work on the Project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at \$6.082 billion (Authority’s 45 percent portion being approximately \$2.737 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Were this option to be exercised, the aggregate delay-related liquidated damages amount referred to in (iii) above would be capped at \$338.0 million per Unit (Authority’s 45 percent portion being approximately \$152.0 million per Unit), and the completion bonus amounts referred to in (iv) above would be \$150.0 million per Unit (Authority’s 45 percent portion being approximately \$68.0 million per Unit).

Summary of Substantial Completion Dates

	Unit 2	Unit 3
Original EPC - May 2008	April 2016	January 2019
EPC - COL Delay - July 2012	March 2017 (+11 months)	May 2018 (-8 months)
Proposed Module Delay - June 2013	December 2017 - March 2018 (+9 to +12 months)	March 2019 (+10 months)
Proposed Re-baselined Schedule - August 2014	December 2018 - June 2019 (+12 to +15 months)	June 2020 (+15 months)
EPC – October 2015 Amendment	August 2019 (+2 to +8 months)	August 2020 (+2 months)

Other Project Developments - In addition to the above-described project issues, the Authority is also aware of financial difficulties that have been experienced by Mangiarotti S.p.A. (Mangiarotti), an Italy based supplier responsible for certain significant components of the project. Since first becoming aware of these financial difficulties, the Consortium has monitored the potential for disruptions in such equipment fabrication and possible responses. In September 2014, Westinghouse completed the acquisition of Mangiarotti, in order to secure this supplier. To date, ten components have been received on-site from Mangiarotti. The remaining two components are in fabrication and expected to be received on-site during the first quarter of 2016.

Nuclear Construction, Risk Factors - The construction of large generating plants such as Summer Nuclear Units 2 and 3 involves significant financial risk. Delays or cost overruns may be incurred as a result of risks such as (a) inconsistent quality of equipment, materials and labor, (b) work stoppages, (c) regulatory matters, (d) unforeseen engineering problems, (e) unanticipated increases in the cost of materials and labor, (f) performance by engineering, procurement, or construction contractors and (g) increases in the cost of debt. Moreover, no nuclear plants have been constructed in the United States using advanced designs such as the Westinghouse AP1000 reactor. Therefore, estimating the cost of construction of any new nuclear plant is inherently uncertain.

To mitigate risk, SCE&G, acting for itself and as agent for the Authority, provides project oversight for Summer Nuclear Units 2 and 3 through its New Nuclear Deployment (NND) business unit. The Authority provides dedicated on-site personnel to monitor and assist NND with the daily oversight of the project. The managerial framework of the NND group is comprised of in-house nuclear industry veterans who lead various internal departments with expertise in: nuclear operations, engineering, construction, maintenance, quality assurance and nuclear regulations. This expertise is dispatched locally to monitor on-site construction as well as domestically (and abroad) to provide surveillance at all major equipment manufacturers. In addition, NND representatives make frequent visits and work closely with the Consortium to monitor progress and issues (engineering, labor, supplier issues, etc.) associated with the AP1000 nuclear power units currently under construction in China, as well as the AP1000 units currently under development at nearby Plant Vogtle in Waynesboro, Georgia.

FINANCING ACTIVITIES

Traditionally, the Authority has amortized its debt taking into consideration the potential termination of the Central Agreement, previously defined, and the expected lives of its capital assets. In light of the May 20, 2013 extension of the earliest possible termination date of the Central Agreement from 2030 to 2058, the Authority is in the process of extending the average life of its debt in order to better align its debt amortization to the expected lives of its capital assets. The Authority expects to achieve this alignment through a combination of selling longer dated debt for a portion of the Authority's capital needs, and restructuring to extend the maturity of a portion of its existing debt. While the size and scope of this restructuring program will evolve over time, the Authority estimates that it has substantially completed the restructuring portion of the program by refinancing and extending approximately \$600.0 million of its existing debt.

The Authority currently has a total construction budget associated with a 45 percent ownership interest in the Summer Nuclear Units 2 and 3 to be approximately \$5.1 billion which includes costs for transmission, initial fuel core and construction of the units. To date, the Authority has financed approximately \$3.7 billion for construction from proceeds of issues sold beginning in 2008. The Authority intends to fund the remaining construction with the proceeds of additional bond sales projected in calendar years 2016 through 2018 and proceeds from the sale of a five percent project ownership interest to SCE&G. While the Authority expects to fund the remaining construction of Summer Nuclear Units 2 and 3 with Revenue Obligations and Commercial Paper Notes, it also has a pending application with the Department of Energy (DOE) for a loan guarantee to fund construction should it be beneficial to do so.

LIQUIDITY AND CAPITAL RESOURCES

Santee Cooper has significant cash flow from operating activities, access to capital markets, bank facilities and special funds deposit balances.

At December 31, 2015, Santee Cooper had \$2.1 billion of cash and investments, of which \$644.5 million was available to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled \$210.5 million.

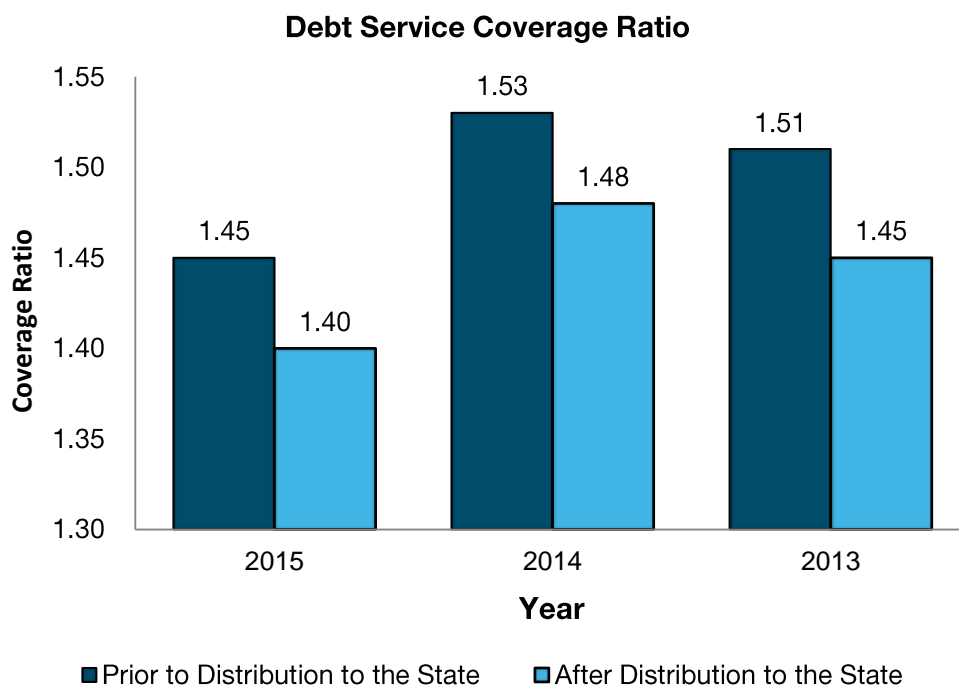
Revolving credit agreements used to support the issuance of commercial paper totaled \$750.0 million at December 31, 2015. The agreements with five banks mature at various dates in 2017 and 2018 and management expects to renew or replace the agreements as needed prior to expiration.

In addition, to obtain other funds, if needed, the Authority entered into a new Revolving Credit Agreement with Barclays Bank PLC in October, 2015. This agreement allows the Authority to borrow up to \$200.0 million and expires on November 27, 2019.

Net cash used by the Authority during 2015 was \$178.8 million. This decrease in cash was due to net cash provided by operating activities of \$237.6 million, offset by cash used in financing and investing activities of \$75.5 million and \$340.9 million, respectively.

DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2015, 2014 and 2013 is shown below:



Note: Years 2014 and 2013 were recalculated using the 2015 approved methodology.

BOND RATINGS

Bond ratings assigned by various agencies for the years ended December 31, 2015, 2014 and 2013 were as follows:

Agency / Lien Level	2015	2014	2013
Fitch Ratings			
Revenue Obligations	A+	A+	AA-
Commercial Paper	F1	F1	F1+
Moody's Investors Service, Inc.			
Revenue Obligations	A1	A1	A1
Commercial Paper	P-1	P-1	P-1
Standard & Poor's Rating Services			
Revenue Obligations	AA-	AA-	AA-
Commercial Paper	A-1	A-1	A-1
Taxable LIBOR Index Bonds	N/A	SP-1+	SP-1+

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Bond Market Transactions for Years 2015, 2014 and 2013

YEAR 2015

Revenue Obligations:	2015 Tax-exempt Refunding and Improvement Series A	Par Amount:	\$ 598,960,000
Purpose:	Refund a portion of the following: 2006 Series A, 2007 Series A, 2008 Series A, and 2009 Series B	Date Closed:	February 26, 2015
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.53 percent		
Revenue Obligations:	2015 Taxable Series D	Par Amount:	\$ 169,657,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	February 26, 2015
Comments:	Taxable bonds with an all-in true interest cost of 4.28 percent		
Revenue Obligations:	2015 Tax-exempt Refunding Series B	Par Amount:	\$ 64,870,000
Purpose:	Refund a portion of the following: 2005 Refunding Series C	Date Closed:	April 7, 2015
Comments:	Tax-exempt bonds with an all-in true interest cost of 2.20 percent		
Revenue Obligations:	2015 Series M1 – Current Interest Bearing Bonds (CIBS)	Par Amount:	\$ 28,879,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 21, 2015
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2015 Series M1 – Capital Appreciation Bonds (CABS)	Par Amount:	\$ 7,257,600
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 21, 2015
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2015 Tax-Exempt Refunding Series C	Par Amount:	\$ 270,170,000
Purpose:	Refund a portion of the following: 2005 Refunding Series A and 2005 Refunding Series B	Date Closed:	October 6, 2015
Comments:	Tax-exempt bonds with an all-in true interest cost of 2.14 percent		
Revenue Obligations:	2015 Tax-Exempt Series E	Par Amount:	\$ 300,000,000
Purpose:	To retire certain Commercial Paper Notes and to finance a portion of the Authority's ongoing capital program	Date Closed:	December 22, 2015
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.74 percent		

YEAR 2014

Revenue Obligations:	2014 Series M1 - Current Interest Bearing Bonds (CIBS)	Par Amount:	\$ 32,393,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 22, 2014
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2014 Series M1 - Capital Appreciation Bonds (CABS)	Par Amount:	\$ 7,191,800
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 22, 2014
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2014 Tax-exempt Series A	Par Amount:	\$ 600,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	July 9, 2014
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.92 percent		
Revenue Obligations:	2014 Tax-exempt Refunding Series B	Par Amount:	\$ 42,275,000
Purpose:	Refund a portion of the following: 2004 Series A	Date Closed:	July 9, 2014
Comments:	Tax-exempt bonds with an all-in true interest cost of 4.41 percent		
Revenue Obligations:	2014 Tax-Exempt Refunding Series C and Taxable Refunding Series D	Par Amount:	\$ 736,320,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A, 2005 Refunding Series A, 2006 Series A, 2006 Refunding Series C, 2007 Series A, 2007 Refunding Series B, 2008 Series A, 2009 Series B, 2010 Refunding Series B, 2011 Refunding Series B, 2012 Refunding Series A, 2012 Refunding Series B, 2012 Refunding Series C, 2012 Series D, and 2013 Taxable Series D London Interbank Offered Rate Index (LIBOR Index)	Date Closed:	October 28, 2014
Comments:	Tax-exempt and taxable bonds with an all-in true interest cost of 3.78 percent		

Bond Market Transactions for Years 2015, 2014 and 2013 (continued)

YEAR 2013

Revenue Obligations:	2013 Series M1 - Current Interest Bearing Bonds (CIBS)	Par Amount:	\$ 18,219,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 23, 2013
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2013 Series M1 - Capital Appreciation Bonds (CABS)	Par Amount:	\$ 5,035,800
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 23, 2013
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2013 Tax-exempt Series A	Par Amount:	\$ 252,655,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	August 21, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.32 percent		
Revenue Obligations:	2013 Tax-exempt Refunding Series B	Par Amount:	\$ 388,730,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A, 2004 Series A, 2006 Series A, 2007 Series A, 2008 Taxable Series B, 2009 Series B, 2011 Taxable Series A (LIBOR Index) and 2012 Series D	Date Closed:	August 21, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.32 percent		
Revenue Obligations:	2013 Taxable Series C	Par Amount:	\$ 250,000,000
Purpose:	Refund a portion of the following: 2003 Refunding Series A and 2008 Taxable Series B	Date Closed:	August 21, 2013
Comments:	Taxable bonds with an all-in true interest cost of 5.83 percent		
Revenue Obligations:	2013 Taxable Series D (LIBOR Index Bonds)	Par Amount:	\$ 450,000,000
Purpose:	Refund a portion of the following: 2008 Taxable Series B, 2011 Taxable Series A (LIBOR Index) and 2012 Refunding Series C	Date Closed:	August 21, 2013
Comments:	Taxable bonds with variable interest rate set monthly based on the London Interbank Offered Rate (LIBOR) plus 87.5 - 110.0 basis points		
Revenue Obligations:	2013 Tax-exempt Series E	Par Amount:	\$ 506,765,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	October 4, 2013
Comments:	Tax-exempt bonds with an all-in true interest cost of 5.34 percent		



Report of Independent Auditor

The Advisory Board and Board of Directors
South Carolina Public Service Authority
Moncks Corner, South Carolina

Report on the Financial Statements

We have audited the accompanying combined financial statements of the South Carolina Public Service Authority (the "Authority") (a component unit of the state of South Carolina), which comprise the combined statements of net position as of December 31, 2015 and 2014, and the related combined statements of revenues, expenses, and changes in net position and cash flows for the years then ended, and the related notes to the combined financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the combined financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of combined financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express opinions on these combined financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Audit Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the combined financial statements are free from material misstatement. An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the combined financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the combined financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Authority's preparation and fair presentation of the combined financial statements in order to design audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the combined financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the combined financial statements referred to above present fairly, in all material respects, the respective financial position of the Authority as of December 31, 2015 and 2014, and results of its operations and its cash flow for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Emphasis of Matter

As discussed in Note 15 to the combined financial statements, the Authority adopted Governmental Accounting Standards Board Statement No. 68, *Accounting and Financial Reporting for Pensions – an Amendment of GASB Statement No. 27*, and Statement No. 71, *Pension Transition for Contributions made Subsequent to the Measurement Date – an Amendment of GASB Statement No. 68*. As a result, net position as of December 31, 2014 in the Statement of Revenues, Expenses and Changes in Net Position has been restated. Our opinion is not modified with respect to this matter.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis be presented to supplement the combined financial statements. Such information, although not a part of the combined financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the combined financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the combined financial statements, and other knowledge we obtained during our audit of the combined financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming opinions on the combined financial statements as a whole. The Chairman and CEO Letter, Corporate Statistics, Audit Committee Chairwoman's Letter, Leadership, and Office Locations as listed in the table of contents of the annual report are presented for purposes of additional analysis and are not a required part of the combined financial statements. Such information has not been subjected to the auditing procedures applied in our audits of the combined financial statements, and accordingly, we do not express an opinion on them.

Other Reporting Required by Government Auditing Standards

In accordance with Government Auditing Standards, we have also issued our report dated February 19, 2016, on or consideration of the Authority's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards, and should be considered in assessing the Authority's internal control over financial reporting and compliance.



Raleigh, North Carolina
February 19, 2016

Combined Statements of Net Position

South Carolina Public Service Authority

As of December 31, 2015 and 2014

	2015	2014
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	\$ 113,413	\$ 171,830
Unrestricted investments	531,120	520,282
Restricted cash and cash equivalents	168,930	289,149
Restricted investments	1,165,630	836,032
Receivables, net of allowance for doubtful accounts of \$1,662 and \$1,555 at December 31, 2015 and 2014, respectively	175,931	187,324
Materials inventory	126,259	113,635
Fuel inventory		
Fossil fuels	507,716	333,648
Nuclear fuel-net	161,990	150,577
Interest receivable	3,357	1,786
Prepaid expenses and other current assets	200,925	233,639
Total current assets	3,155,271	2,837,902
Noncurrent assets		
Restricted cash and cash equivalents	205	352
Restricted investments	126,282	122,657
Capital assets		
Utility plant	7,134,706	7,023,729
Long lived assets-asset retirement cost	507,394	507,394
Accumulated depreciation	(3,476,246)	(3,332,127)
Total utility plant-net	4,165,854	4,198,996
Construction work in progress	3,337,353	2,712,851
Other physical property-net	5,914	5,939
Investment in associated companies	7,001	8,584
Unamortized debt expenses	39,249	35,902
Costs to be recovered from future revenue	240,923	247,359
Regulatory asset-asset retirement obligation	699,748	660,181
Other noncurrent and regulatory assets	215,987	173,870
Total noncurrent assets	8,838,516	8,166,691
Total assets	\$ 11,993,787	\$ 11,004,593
DEFERRED OUTFLOWS OF RESOURCES		
Deferred outflows – pension	\$ 31,430	\$ 0
Accumulated decrease in fair value of hedging derivatives	91,372	69,958
Unamortized loss on refunded and defeased debt	133,932	133,680
Total deferred outflows of resources	\$ 256,734	\$ 203,638
Total assets & deferred outflows of resources	\$ 12,250,521	\$ 11,208,231

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

Combined Statements of Net Position (continued)

South Carolina Public Service Authority

As of December 31, 2015 and 2014

	2015	2014
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long-term debt	\$ 172,896	\$ 149,689
Accrued interest on long-term debt	67,378	79,061
Commercial paper	597,520	410,139
Accounts payable	362,755	260,727
Other current liabilities	99,042	131,766
Total current liabilities	1,299,591	1,031,382
Noncurrent liabilities		
Construction liabilities	6,643	6,377
Net pension liability	286,300	0
Asset retirement obligation liability	1,046,054	1,043,629
Total long-term debt (net of current portion)	6,961,336	6,399,449
Unamortized debt discounts and premiums	345,133	239,713
Long-term debt-net	7,306,469	6,639,162
Other credits and noncurrent liabilities	130,192	110,717
Total noncurrent liabilities	8,775,658	7,799,885
Total liabilities	\$ 10,075,249	\$ 8,831,267
DEFERRED INFLOWS OF RESOURCES		
Deferred inflows - pension	\$ 17,424	\$ 0
Accumulated increase in fair value of hedging derivatives	4,701	1,138
Nuclear decommissioning costs	211,357	207,363
Total deferred inflows of resources	\$ 233,482	\$ 208,501
NET POSITION		
Net invested in capital assets	\$ 1,195,402	\$ 957,835
Restricted for debt service	79,771	108,457
Restricted for capital projects	4,304	6,515
Unrestricted	662,313	1,095,656
Total net position	\$ 1,941,790	\$ 2,168,463
Total liabilities, deferred inflows of resources & net position	\$ 12,250,521	\$ 11,208,231

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Combined Statements of Revenues, Expenses and Changes in Net Position

South Carolina Public Service Authority
Years Ended December 31, 2015 and 2014

	2015	2014
	(Thousands)	
Operating revenues		
Sale of electricity	\$ 1,856,523	\$ 1,975,362
Sale of water	8,069	7,854
Other operating revenue	14,961	14,131
Total operating revenues	1,879,553	1,997,347
Operating expenses		
Electric operating expenses		
Production	123,421	109,194
Fuel	713,308	820,720
Purchased and interchanged power	193,646	237,187
Transmission	26,749	24,885
Distribution	11,216	10,626
Customer accounts	15,316	15,616
Sales	13,476	12,378
Administrative and general	88,899	89,286
Electric maintenance expenses	131,331	116,560
Water operating expenses	2,864	2,687
Water maintenance expenses	910	858
Total operating and maintenance expenses	1,321,136	1,439,997
Depreciation	176,039	173,743
Sums in lieu of taxes	5,313	5,484
Total operating expenses	1,502,488	1,619,224
Operating income	377,065	378,123
Nonoperating revenues (expenses)		
Interest and investment revenue	9,207	29,023
Net decrease in the fair value of investments	(4,455)	(2,017)
Interest expense on long-term debt	(282,564)	(268,989)
Interest expense on commercial paper and other	(3,033)	(4,840)
Amortization expense	6,494	(1,164)
Costs to be recovered from future revenue	(6,435)	19,798
U.S. Treasury subsidy on Build America Bonds	7,559	7,542
Other-net	(49,323)	(8,481)
Total nonoperating revenues (expenses)	(322,550)	(229,128)
Income before transfers	54,515	148,995
Capital contributions & transfers		
Distribution to the State	(20,116)	(20,659)
Total capital contributions & transfers	(20,116)	(20,659)
Change in net position	34,399	128,336
Net position-beginning of period as previously reported	2,168,463	2,040,127
Restatement (Note 15)	(261,072)	0
Total net position-beginning of period as restated	1,907,391	2,040,127
Total net position-ending	\$ 1,941,790	\$ 2,168,463

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

Combined Statements of Cash Flows

South Carolina Public Service Authority

Years Ended December 31, 2015 and 2014

	2015	2014
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	\$ 1,890,839	\$ 1,998,875
Payments to non-fuel suppliers	(787,254)	(124,575)
Payments for fuel	(703,519)	(813,871)
Purchased power	(193,646)	(237,263)
Payments to employees	(175,633)	(162,872)
Other receipts-net	206,834	374,315
Net cash provided by operating activities	237,621	1,034,609
Cash flows from non-capital related financing activities		
Distribution to the State	(20,116)	(20,659)
Proceeds from sale of bonds	13,150	54,105
Proceeds from issuance of commercial paper notes	180,885	229,105
Repayment of commercial paper notes	(13,986)	(105,062)
Refunding / defeasance of long-term debt	(14,065)	(469,708)
Repayment of long-term debt	(119)	(143)
Interest paid on long-term debt	(8,383)	(18,156)
Interest paid on commercial paper and other	(4,321)	(3,286)
Bond issuance and other related costs	694	(7,424)
Net cash provided by (used in) non-capital related financing activities	133,739	(341,228)
Cash flows from capital-related financing activities		
Proceeds from sale of bonds	1,426,644	1,364,075
Proceeds from issuance of commercial paper notes	65,201	59,661
Repayment of commercial paper notes	(44,719)	(145,638)
Refunding / defeasance of long-term debt	(659,490)	(753,782)
Repayment of long-term debt	(139,132)	(95,615)
Interest paid on long-term debt	(338,020)	(304,308)
Interest paid on commercial paper and other	(905)	(2,331)
Construction and betterments of utility plant	(587,228)	(725,145)
Bond issuance and other related costs	100,264	75,525
Other-net	(31,879)	(8,427)
Net cash used in capital related financing activities	(209,264)	(535,985)
Cash flows from investing activities		
Net decrease in investments	(348,516)	(82,694)
Interest on investments	7,637	29,901
Net cash used in investing activities	(340,879)	(52,793)
Net (decrease)/increase in cash and cash equivalents	(178,783)	104,603
Cash and cash equivalents-beginning	461,331	356,728
Cash and cash equivalents-ending	\$ 282,548	\$ 461,331

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

Combined Statements of Cash Flows (continued)

South Carolina Public Service Authority
Years Ended December 31, 2015 and 2014

	2015	2014
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	\$ 377,065	\$ 378,123
<i>Adjustments to reconcile operating income to net cash provided by operating activities</i>		
Depreciation	176,039	173,743
Amortization of nuclear fuel	22,832	22,552
Net power gains involving associated companies	(47,366)	(27,711)
Distributions from associated companies	44,864	23,674
Advances to associated companies	162	(107)
Other income and expenses	(37,049)	3,807
Changes in assets and liabilities		
Accounts receivable-net	11,393	1,768
Inventories	(186,692)	113,581
Prepaid expenses	32,845	(21,928)
Other deferred debits	(48,474)	245,692
Accounts payable	(140,604)	50,545
Other current liabilities	(31,070)	57,779
Other noncurrent liabilities	63,676	13,091
Net cash provided by operating activities	\$ 237,621	\$ 1,034,609

Composition of cash and cash equivalents

Current		
Unrestricted cash and cash equivalents	\$ 113,413	\$ 171,830
Restricted cash and cash equivalents	168,930	289,149
Noncurrent		
Restricted cash and cash equivalents	205	352
Cash and cash equivalents at the end of the year	\$ 282,548	\$ 461,331

NOTES

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A - Reporting Entity - The South Carolina Public Service Authority (the Authority or Santee Cooper), a component unit of the State of South Carolina (the State), was created in 1934 by the State legislature. The Santee Cooper Board of Directors (Board) is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power and wholesale water to the people of South Carolina. Capital projects are funded by bonds, commercial paper and internally generated funds. As authorized by State law, the Board sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States (GAAP) issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting.

The Authority's combined financial statements include the accounts of the Lake Moultrie Water Agency and Lake Marion Regional Water Agency after elimination of inter-company accounts and transactions. The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) for the electric system and the National Association of Regulatory Utility Commissioners (NARUC) for the water systems.

The Authority also complies with policies and practices prescribed by its Board and practices common in both industries. As the Board is authorized to set rates, the Authority follows GASB 62. This standard provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions in the Authority's reporting. This practice affects the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C - Current and Noncurrent - The Authority presents assets and liabilities in order of relative liquidity. The liquidity of an asset is determined by how readily it is expected to be converted to cash and whether restrictions limit the use of the resources. The liquidity of a liability is based on its maturity, or when cash is expected to be used to liquidate the liability.

D - Restricted Assets - For purposes of the Combined Statements of Net Position and Combined Statements of Cash Flows, assets are restricted when constraints are placed on their use by either:

- (1) External creditors, grantors, contributors, or laws or regulations of other governments; or
- (2) Law through constitutional provisions or enabling legislation.

Assets not meeting the requirements of restricted are classified as unrestricted.

E- Cash and Cash Equivalents - For purposes of the Combined Statements of Net Position and Combined Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less and cash on deposit with financial institutions as unrestricted and restricted cash and cash equivalents.

F - Inventory - Material and fuel inventories are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost.

G - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead and interest capitalized during construction. Interest is capitalized only when interest payments are funded through borrowings. The Authority capitalized \$43.5 million and \$59.3 million of interest in 2015 and 2014, respectively. Other interest expense is recovered currently through rates. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

H - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the gross plant balance of various classes of assets which includes appropriate adjustments for cost of removal and salvage. The Authority periodically has depreciation studies performed by independent parties to assist management in establishing appropriate composite depreciation rates. For assets not grouped in a plant class, straight-line depreciation is used over the estimated useful life of the asset.

Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were as follows:

Years Ended December 31,	2015	2014
Annual average depreciation percentages	2.6%	2.6%

I - Retirement of Long Lived Assets - The Authority follows the guidance of FASB ASC 410 in regards to the decommissioning of V.C. Summer Nuclear Station (Summer Nuclear) and closing coal-fired generation ash ponds. The requirements for both were recorded within capital assets on the accompanying Combined Statements of Net Position.

The asset retirement obligation (ARO) is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes the Authority's transactions:

Years Ended December 31,	2015			2014		
	Nuclear	Ash Ponds	Total	Nuclear	Ash Ponds	Total
(Millions)						
Reconciliation of ARO Liability:						
Balance as of January 1,	\$ 678.8	\$ 364.8	\$ 1,043.6	\$ 664.4	\$ 359.8	\$ 1,024.2
Accretion expense	14.7	(12.3)	2.4	14.4	5.0	19.4
Balance as of December 31,	\$ 693.5	\$ 352.5	\$ 1,046.0	\$ 678.8	\$ 364.8	\$ 1,043.6
Asset Retirement Cost (ARC):	\$ 334.3	\$ 173.1	\$ 507.4	\$ 334.3	\$ 173.1	\$ 507.4

J - Reporting Impairment Losses - The Authority's Board authorized the retirement of six generating units during 2012. December 2012 was set for the permanent retirement date for four coal-fired generating units (Grainger Units 1 and 2 and Jefferies Units 3 and 4). In compliance with GASB 42, the required accounting entries were recorded for capital assets, depreciation effect, costs to be recovered from future revenue (CTBR) expense, materials and supplies.

2015 updates include the sale of Grainger Unit 1 and 2 for scrap and continued preparation for a future sale of Jefferies Units 3 and 4 generating station assets. In addition, sales of coal (fuel stock pile) from the Jefferies and Grainger generating stations also continued. The sale of coal will continue at both generation sites (Jefferies and Grainger) until fully depleted.

The Authority continues to implement the appropriate processes to fully close the retired units in order to remain in compliance with regulatory requirements. It should be noted that the closure of the ash ponds at each site will result in additional entries and adjustments to accumulated depreciation, ARO and various other balances in subsequent years.

K - Other Regulatory Assets - The Authority made the decision in 2007 to build a coal-fired generation plant in Florence County, S.C. In 2009 the Authority chose not to pursue this option. Assets related to this project are classified as other current and noncurrent regulatory assets. Management has chosen to write off the total asset balance of \$264.4 million over a period ending December 2020. Accordingly, \$42.6 million and \$9.2 million were written off in 2015 and 2014, respectively. The remaining balance outstanding at December 31, 2015 is \$212.6 million.

L - Investment in Associated Companies - The Authority is a member of The Energy Authority (TEA). Approximate ownership interests were as follows:

Years Ended December 31,	2015	2014
Owners	Ownership (%)	
City Utilities of Springfield (Missouri)	5.55	5.00
Cowlitz Public Utility District (Washington)	5.55	5.00
Gainesville Regional Utilities (Florida)	5.55	5.00
American Municipal Power (Ohio)	16.67	17.00
JEA (Florida)	16.67	17.00
MEAG Power (Georgia)	16.67	17.00
Nebraska Public Power District (Nebraska)	16.67	17.00
Santee Cooper (South Carolina)	16.67	17.00
Total	100.00	100.00

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. It is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, it assists members with fuel hedging activities and acts as an agent in the execution of forward transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

Years Ended December 31,	2015	2014
	(Thousands)	
TEA Investment:		
Balance as of January 1,	\$ 8,281	\$ 6,644
Reduction to power costs and increases in electric revenues	43,809	25,336
Less: Distributions from TEA	44,864	23,674
Less: Other (includes equity losses)	368	25
Balance as of December 31,	\$ 6,858	\$ 8,281
Due To/Due From TEA:		
Payable to	\$ 26,839	\$ 26,125
Receivable from	\$ 3,245	\$ 782

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. These guarantees are within the scope of FASB ASC 952. Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest. After such contributions have been affected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by providing advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board. At December 31, 2015, the trade guarantees are an amount not to exceed approximately \$93.3 million.

The Authority was also a member of Colectric Partners (Colectric). Members consisted of JEA (Florida), MEAG Power (Georgia), Nebraska Public Power District (Nebraska) and Santee Cooper (South Carolina), all owning an equal 25 percent share.

Colectric provided public power utilities with key project and business management resources. The Authority participated in several of Colectric's initiatives. The largest involved managing the major gas turbine overhauls, thereby promoting the sharing of spare parts and technical expertise. Another was the strategic sourcing initiative, intended to achieve major cost savings through volume purchasing leverage. Since 2001, cumulative net direct cost and direct savings have been \$4.4 million and \$18.8 million, respectively. Due to the maintenance sharing initiative ceasing, the Colectric Board of Directors voted in January 2015 to cease operations of Colectric effective March 31, 2015.

The Authority's exposure related to Colectric was limited to its capital investment, any accounts receivable and any indemnifications related to agreements between Colectric and the Authority. These indemnifications are within the scope of FASB ASC 952. The Authority's initial investment in Colectric was \$413,000. The balance in its member equity account at December 31, 2015 and 2014 was approximately \$5,000 and \$194,000, respectively.

On October 1, 2013, the Authority along with MEAG Power became originating members of TEA Solutions. JEA and Cowlitz Public Utility District joined later in 2013. TEA Solutions is a publicly supported non-profit corporation. Members and ownership interests were as follows:

Years Ended December 31,	2015	2014
Owners	Ownership (%)	
Cowlitz Public Service District (Washington)	8.0	8.0
American Municipal Power (Ohio)	23.0	23.0
JEA (Florida)	23.0	23.0
MEAG Power (Georgia)	23.0	23.0
Santee Cooper (South Carolina)	23.0	23.0
Total	100.0	100.0

TEA Solutions was formed mainly to (1) coordinate the operation of electric generation resources and the purchase and sale of electric power on behalf of the corporation's clients; (2) coordinate the purchase and sale of natural gas relating to fuel for clients' generation of electric energy or relating to clients' operation of a retail gas distribution system; and (3) provide consulting and software services to clients.

The Authority funded its initial share of TEA Solutions with a \$150,000 contribution in 2013. This contribution was to cover legal, consulting and other start-up costs pertaining to TEA Solutions. The Authority's exposure relating to TEA Solutions is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. The balance in its member equity account at December 31, 2015 and 2014 was approximately \$122,000 and \$110,000, respectively.

M – Deferred Outflows / Deferred Inflows of Resources – In addition to assets, the Combined Statements of Net Position reports a separate section for Deferred Outflows of Resources. These items represent a consumption of net position that applies to a future period and until that time will not be recognized as an expense or expenditure. The Authority has three items meeting this criterion: (1) deferred outflows – pension; (2) accumulated decrease in fair value of hedging derivatives; and (3) unamortized loss on refunded and defeased debt.

In addition to liabilities, the Combined Statements of Net Position also reports a separate section for Deferred Inflows of Resources. These items represent an acquisition of net position that applies to a future period and until that time will not be recognized as revenue. The Authority has three items meeting this criterion: (1) deferred inflows – pension; (2) accumulated increase in fair value of hedging derivatives; and (3) nuclear decommissioning costs.

The following table summarizes the Authority's total deferred items:

Years Ended December 31,	2015	2014
	(Thousands)	
Deferred outflows of resources	\$ 256,734	\$ 203,638
Deferred inflows of resources	\$ 233,482	\$ 208,501

N - Accounting for Derivative Instruments - In compliance with GASB 53 and 64, the annual changes in the fair value of effective hedging derivative instruments are required to be deferred (reported as deferred outflows of resources and deferred inflows of resources on the Combined Statements of Net Position). Deferral of changes in fair value generally lasts until the transaction involving the hedged item ends.

Natural gas and heating oil, core business commodity inputs for the Authority, have historically been hedged in an effort to mitigate gas and oil cost risk by reducing cost volatility and improving cost effectiveness. Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as fuel costs are incurred in the production cycle.

A summary of the Authority's derivative activity for years ended December 31, 2015 and 2014 is below:

Cash Flow Hedges and Summary of Activity				
Years Ended December 31,		2015	2014	
	Account Classification		(Millions)	
<i>Fair Value</i>				
Natural gas	Regulatory assets/liabilities	\$	(84.5)	\$ (60.3)
Heating oil	Regulatory assets/liabilities		(2.2)	(8.6)
<i>Changes in Fair Value</i>				
Natural gas	Regulatory assets/liabilities	\$	(24.2)	\$ (48.8)
Heating oil	Regulatory assets/liabilities		6.4	(8.8)
<i>Recognized Net Gains (Losses)</i>				
Natural gas	Operating expense-fuel	\$	(44.6)	\$ 5.8
Heating oil	Operating expense-fuel		(11.0)	(0.4)
<i>Realized But Not Recognized Net Gains (Losses)</i>				
Natural gas	Regulatory assets/liabilities	\$	(8.8)	\$ 2.7
Heating oil	Regulatory assets/liabilities		(0.2)	0.0
<i>Notional</i>				
			MBTUs	
Natural gas			107,033	61,980
			Gallons (000s)	
Heating oil			6,930	12,012

O - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers but not billed are accrued monthly. Accrued revenue for retail customers totaled \$13.0 million in 2015 and \$15.3 million in 2014.

Fuel costs are reflected in operating expenses as fuel is consumed. Fuel expense for all customers is billed utilizing rates and contracts, the majority of which include fuel adjustment provisions based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period.

P - Bond Issuance Costs and Refunding Activity - GASB 62 requires that any gains or losses resulting from extinguishment of debt be expensed at the time of extinguishment. GASB 65 requires that debt issuance costs be expensed in the period incurred. In order to align the impact of these pronouncements with the Authority's rate making process, in October 2012, the Board authorized the use of regulatory accounting to allow continuation of prior accounting treatment with regard to these costs.

Consistent with prior accounting periods, unamortized debt discounts, premiums and expenses are amortized to income over the terms of the related debt issues. Gains or losses on refunded and extinguished debt are amortized to earnings over the shorter of the remaining life of the refunded debt or the life of the new debt.

Q - Distribution to the State - Any and all net earnings of the Authority not necessary for the prudent conduct and operation of its business in the best interests of the Authority or to pay the principal of and interest on its bonds, notes, or other evidences of indebtedness or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others must be paid over semiannually to the State Treasurer for the general funds of the State. Nothing in this section shall prohibit the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems. (Code of Laws of South Carolina, as amended Section 58-31-110).

Distributions made to the State in 2015 and 2014 totaled approximately \$20.1 million and \$20.7 million, respectively.

R - New Accounting Standards

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 67	Financial Reporting for Pension Plans - an amendment of GASB 25	
Issue Date: June 2012	Effective for Periods Beginning After: June 15, 2013	
Description:	The objective of GASB 67 is to improve financial reporting by state and local governmental pension plans. GASB 67 results from a comprehensive review of the effectiveness of existing standards of accounting and financial reporting for pensions with regard to providing decision-useful information, supporting assessments of accountability and interperiod equity and creating additional transparency. GASB 67 replaces the requirements of Statements No. 25, <i>Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans</i> and No. 50, <i>Pension Disclosures</i> .	Implemented in 2015
Statement No. GASB 68	Accounting and Financial Reporting for Pensions - an amendment of GASB Statement No. 27	
Issue Date: June 2012	Effective for Periods Beginning After: June 15, 2014	
Description:	The primary objective of this Statement is to improve accounting and financial reporting by state and local governments for pensions. It also improves information provided by state and local governmental employers about financial support for pensions that is provided by other entities.	Implemented in 2015
Statement No. GASB 69	Government Combinations and Disposals of Government Operations	
Issue Date: January 2013	Effective for Periods Beginning After: December 15, 2013	
Description:	This Statement establishes accounting and financial reporting standards related to government combinations and disposals of government operations. As used in this Statement, the term "government combinations" includes a variety of transactions referred to as mergers, acquisitions and transfers of operations.	Reviewed and no action required.
Statement No. GASB 70	Accounting and Financial Reporting for Nonexchange Financial Guarantees	
Issue Date: April 2013	Effective for Periods Beginning After: June 15, 2013	
Description:	The objective of this Statement is to improve accounting and financial reporting by state and local governments that extend and receive nonexchange financial guarantees. This Statement requires a government that extends a nonexchange financial guarantee to recognize a liability when qualitative factors and historical data, if any, indicate that it is more likely than not the government will be required to make a payment on the guarantee.	Reviewed and no action required.

Statement No. GASB 71	Pension Transition for Contributions Made Subsequent to the Measurement Date - an amendment of GASB Statement No. 68	
Issue Date: November 2013	The provisions of this Statement should be applied simultaneously with the provisions of Statement 68.	
Description:	The objective of this Statement is to address an issue regarding application of the transition provisions of Statement No. 68, <i>Accounting and Financial Reporting for Pensions</i> . The issue relates to amounts associated with contributions, if any, made by a state of local government employer or nonemployer contributing entity to a defined benefit pension plan after the measurement date of the government's beginning net pension liability.	Implemented in 2015
Statement No. GASB 72	Fair Value Measurement and Application	
Issue Date: February 2015	Effective for Periods Beginning After: June 15, 2015	
Description:	This Statement addresses accounting and financial reporting issues related to fair value measurements. The definition of <i>fair value</i> is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. This Statement provides guidance for determining a fair value measurement for financial reporting purposes. This Statement also provides guidance for applying fair value to certain investments and disclosures related to all fair value measurements.	Under Review
Statement No. GASB 73	Accounting and Financial Reporting for Pensions and Related Assets That Are Not within the Scope of GASB Statement 68, and Amendments to Certain Provisions of GASB Statements 67 and 68	
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2015	
Description:	The objective of this Statement is to improve the usefulness of information about pensions included in the general purpose external financial reports of state and local governments for making decisions and assessing accountability. This Statement establishes requirements for defined benefit pensions that are not within the scope of Statement No. 68, <i>Accounting and Financial Reporting for Pensions</i> , as well as for the assets accumulated for purposes of providing those pensions. In addition, it establishes requirements for defined contribution pensions that are not within the scope of Statement 68. It also amends certain provisions of Statement No. 67, <i>Financial Reporting for Pension Plans</i> and Statement 68 for pension plans and pensions that are within their respective scopes.	Under Review
Statement No. GASB 74	Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans	
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to improve the usefulness of information about postemployment benefits other than pensions (other postemployment benefits or OPEB) included in the general purpose external financial reports of state and local governmental OPEB plans for making decisions and assessing accountability. This Statement replaces Statements No. 43, <i>Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans</i> , as amended, and No. 57, <i>OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans</i> . It also includes requirements for defined contribution OPEB plans that replace the requirements for those OPEB plans in Statement No. 25, <i>Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans</i> , as amended, Statement 43, and Statement No. 50, <i>Pension Disclosures</i> .	Under Review
Statement No. GASB 75	Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions	
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2017	
Description:	The primary objective of this Statement is to improve accounting and financial reporting by state and local governments for postemployment benefits other than pensions (other postemployment benefits or OPEB). It also improves information provided by state and local governmental employers about financial support for OPEB that is provided by other entities. This Statement replaces the requirements of Statements No. 45, <i>Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions</i> , as amended, and No. 57, <i>OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans</i> , for OPEB. Statement No. 74, <i>Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans</i> , establishes new accounting and financial reporting requirements for OPEB plans.	Under Review

Statement No. GASB 76	The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments	
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2015	
Description:	<p>The objective of this Statement is to identify—in the context of the current governmental financial reporting environment—the hierarchy of generally accepted accounting principles (GAAP). The “GAAP hierarchy” consists of the sources of accounting principles used to prepare financial statements of state and local governmental entities in conformity with GAAP and the framework for selecting those principles. This Statement reduces the GAAP hierarchy to two categories of authoritative GAAP and addresses the use of authoritative and nonauthoritative literature in the event that the accounting treatment for a transaction or other event is not specified within a source of authoritative GAAP.</p> <p>This Statement supersedes Statement No. 55, <i>The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments</i>. The requirements of this Statement are effective for financial statements for periods beginning after June 15, 2015, and should be applied retroactively. Earlier application is permitted.</p>	Under Review
Statement No. GASB 77	Tax Abatement Disclosures	
Issue Date: August 2015	Effective for Periods Beginning After: December 15, 2015	
Description:	<p>Financial statements prepared by state and local governments in conformity with generally accepted accounting principles provide citizens and taxpayers, legislative and oversight bodies, municipal bond analysts, and others with information they need to evaluate the financial health of governments, make decisions, and assess accountability. This information is intended, among other things, to assist these users of financial statements in assessing (1) whether a government’s current-year revenues were sufficient to pay for current-year services (known as interperiod equity), (2) whether a government complied with finance-related legal and contractual obligations, (3) where a government’s financial resources come from and how it uses them, and (4) a government’s financial position and economic condition and how they have changed over time.</p> <p>This Statement requires disclosure of tax abatement information about (1) a reporting government’s own tax abatement agreements and (2) those that are entered into by other governments and that reduce the reporting government’s tax revenues.</p>	Under Review
Statement No. GASB 78	Pensions Provided Through Certain Multiple-Employer Defined Benefit Pension Plans	
Issue Date: December 2015	Effective for Periods Beginning After: December 15, 2015	
Description:	<p>This Statement amends the scope and applicability of Statement 68 to exclude pensions provided to employees of state or local governmental employers through a cost-sharing multiple-employer defined benefit pension plan that (1) is not a state or local governmental pension plan, (2) is used to provide defined benefit pensions both to employees of state or local governmental employers and to employees of employers that are not state or local governmental employers, and (3) has no predominant state or local governmental employer (either individually or collectively with other state or local governmental employers that provide pensions through the pension plan). This Statement establishes requirements for recognition and measurement of pension expense, expenditures, and liabilities; note disclosures; and required supplementary information for pensions that have the characteristics described above.</p>	Under Review
Statement No. GASB 79	Certain External Investment Pools and Pool Participants	
Issue Date: December 2015	Effective for Periods Beginning After: June 15, 2015	
Description:	<p>This Statement addresses accounting and financial reporting for certain external investment pools and pool participants. Specifically, it establishes criteria for an external investment pool to qualify for making the election to measure all of its investments at amortized cost for financial reporting purposes. An external investment pool qualifies for that reporting if it meets all of the applicable criteria established in this Statement. The specific criteria address (1) how the external investment pool transacts with participants; (2) requirements for portfolio maturity, quality, diversification, and liquidity; and (3) calculation and requirements of a shadow price. Significant noncompliance prevents the external investment pool from measuring all of its investments at amortized cost for financial reporting purposes. Professional judgment is required to determine if instances of noncompliance with the criteria established by this Statement during the reporting period, individually or in the aggregate, were significant.</p>	Under Review

NOTE 2 – COSTS TO BE RECOVERED FROM FUTURE REVENUE (CTBR)

The Authority's rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with GASB 62, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as CTBR. The recovery of outstanding amounts recorded as CTBR will coincide with the repayment of the applicable outstanding debt. The Authority's summary of CTBR activity is recapped below:

Years Ended December 31,	2015	2014
	(Millions)	
CTBR regulatory asset:		
Balance	\$ 240.9	\$ 247.4
CTBR expense/(reduction to expense):		
Net expense	\$ 6.4	\$ (19.8)

NOTE 3 – CAPITAL ASSETS

Capital asset activity for the years ended December 31, 2015 and 2014 was as follows:

	Beginning Balances	Increases	Decreases	Ending Balances
	Year 2015 (Thousands)			
Utility plant	\$ 7,023,729	\$ 156,369	\$ (45,392)	\$ 7,134,706
Long lived assets-asset retirement cost	507,394	0	0	507,394
Accumulated depreciation	(3,332,127)	(212,951)	68,832	(3,476,246)
Total utility plant-net	4,198,996	(56,582)	23,440	4,165,854
Construction work in progress	2,712,851	781,075	(156,573)	3,337,353
Other physical property-net	5,939	0	(25)	5,914
Totals	\$ 6,917,786	\$ 724,493	\$ (133,158)	\$ 7,509,121
	Year 2014 (Thousands)			
Utility plant	\$ 6,910,962	\$ 156,358	\$ (43,591)	\$ 7,023,729
Long lived assets-asset retirement cost	507,394	0	0	507,394
Accumulated depreciation	(3,150,020)	(210,661)	28,554	(3,332,127)
Total utility plant-net	4,268,336	(54,303)	(15,037)	4,198,996
Construction work in progress	2,100,631	768,586	(156,366)	2,712,851
Other physical property-net	6,084	79	(224)	5,939
Totals	\$ 6,375,051	\$ 714,362	\$ (171,627)	\$ 6,917,786

NOTE 4 – CASH AND INVESTMENTS HELD BY TRUSTEE AND FUND DETAILS

All cash and investments of the Authority are held and maintained by custodians and trustees. The use of unexpended proceeds from sale of bonds, debt service funds and other sources is designated in accordance with applicable provisions of various bond resolutions, lease agreements, the Enabling Act included in the South Carolina Code of Laws (the Enabling Act) or by management directive. Restricted funds have constraints placed on their use (see Note 1 - D – “Restricted Assets”). The use of unrestricted funds may be either designated for a specific use by management directive or undesignated, but are available to provide liquidity for operations as needed.

Following are the details of the Authority’s funds which are classified in the accompanying financial statements as unrestricted and restricted cash, cash equivalents and investments:

Years Ended December 31,	2015			2014		
Funds	Cash & Cash Equivalents	Investments	Total	Cash & Cash Equivalents	Investments	Total
(Thousands)						
Current Unrestricted:						
Capital Improvement	\$ 23,534	\$ 142,892	\$ 166,426	\$ 44,216	\$ 132,728	\$ 176,944
Debt Reduction	3,575	53,879	57,454	10,713	45,224	55,937
Funds from Taxable Borrowings	9,216	176,509	185,725	11,457	130,895	142,352
General Improvement	579	2,448	3,027	1,438	1,450	2,888
Internal Nuclear						
Decommissioning Fund	2,764	81,230	83,994	415	83,090	83,505
Nuclear Fuel	2,701	13,017	15,718	5,318	23,999	29,317
Revenue and Operating	63,811	15,289	79,100	72,021	33,007	105,028
Special Reserve and Other	7,233	45,856	53,089	26,252	69,889	96,141
Total	\$ 113,413	\$ 531,120	\$ 644,533	\$ 171,830	\$ 520,282	\$ 692,112
Current Restricted:						
Debt Service Funds	\$ 68,190	\$ 78,959	\$ 147,149	\$ 65,178	\$ 122,340	\$ 187,518
Funds from Tax-exempt						
Borrowings	65,069	1,062,535	1,127,604	164,567	691,392	855,959
Other	35,671	24,136	59,807	59,404	22,300	81,704
Total	\$ 168,930	\$ 1,165,630	\$ 1,334,560	\$ 289,149	\$ 836,032	\$ 1,125,181
Noncurrent Restricted:						
External Nuclear						
Decommissioning Trust	\$ 205	\$ 126,282	\$ 126,487	\$ 352	\$ 122,657	\$ 123,009
Total	\$ 205	\$ 126,282	\$ 126,487	\$ 352	\$ 122,657	\$ 123,009
TOTAL FUNDS	\$ 282,548	\$ 1,823,032	\$ 2,105,580	\$ 461,331	\$ 1,478,971	\$ 1,940,302

Cash and investments as of December 31, consisted of the following:

Cash/Deposits	\$ 64,639	\$ 87,503
Investments	2,040,941	1,852,799
Total cash and investments	\$ 2,105,580	\$ 1,940,302

Current Unrestricted Funds – These funds are used for operating activities for the Authority’s respective systems. Although funds are segregated per management directive based on their intended use, since no restrictions apply, the funds are available to provide additional liquidity for operations. Included in this category is the internal Nuclear Decommissioning Fund intended by management to be used to offset future nuclear decommissioning costs and represents amounts in excess of the mandated Nuclear Regulatory Commission (NRC) decommissioning requirement which is funded separately in an external Nuclear Decommissioning Trust. Also included are funds from taxable borrowings intended to be used for both capital construction costs and for working capital purposes, as expected at the time proceeds are borrowed.

Current Restricted Funds – These funds are restricted in their allowed use. Debt service funds are restricted for payment of principal and interest debt service on outstanding debt. Funds from tax-exempt borrowings are intended to be used for capital construction costs as expected at the time proceeds are borrowed and are restricted pursuant to sections of both the U.S. Treasury Regulations and the Internal Revenue Code that govern the use of tax-exempt debt. Other funds are restricted for other special purposes.

Noncurrent Restricted Funds – These funds are restricted as to their specific use. The external Nuclear Decommissioning Trust is restricted for future nuclear decommissioning costs and represents the mandated NRC funding requirements.

The Authority’s investments are authorized by the Enabling Act, the Authority’s investment policy and the Revenue Obligation Resolution. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds and U.S. Treasury Obligations, all of which are limited to a 10 year maximum maturity in all portfolios, except the decommissioning funds. Certificate of Deposits and Repurchase Agreements are also authorized with a maximum maturity of one year.

All debt securities are recorded at their fair value with gains and losses in fair value reflected as a component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Position.

The Authority’s investment activity in all fund categories is summarized as follows:

Years Ended December 31,	2015	2014
Total Portfolio	(Billions)	
Total investments	\$ 2.0	\$ 1.8
Purchases	49.6	71.2
Sales	49.4	71.0
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	\$ 210.5	\$ 206.5
Purchases	697.8	691.4
Sales	691.9	685.7
Unrealized holding gain/(loss)	(1.7)	17.0
Repurchase Agreements (1)	(Millions)	
Balance at December 31	\$ 98.9	\$ 304.1

(1) Securities underlying repurchase agreements must have a market value of at least 102 percent of the cost of the repurchase agreement and are delivered by broker/dealers to the Authority's custodial agents.

Common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk and foreign currency risk are as follows:

Risk Type	Exposure																																																
Credit Risk - Risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. Measured by the assignment of rating by a nationally recognized statistical rating organization.	As of December 31, 2015 and 2014, all of the agency securities held by the Authority were rated AAA by Fitch Ratings, Aaa by Moody's Investors Service, Inc. and AA+ by Standard & Poor's Rating Services.																																																
Custodial Credit Risk-Investments - Risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party.	As of December 31, 2015 and 2014, all of the Authority's investment securities are held by the Trustee or Agent of the Authority and therefore, there is no custodial risk for investment securities.																																																
Custodial Credit Risk-Deposits - Risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party.	At December 31, 2015 and 2014, the Authority had no exposure to custodial credit risk for deposits that were uninsured and/or collateral that was held by the bank's agent not in the Authority's name.																																																
Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer.	Investments in any one issuer (other than U. S. Treasury securities) that represent five percent or more of total Authority investments at December 31, 2015 and 2014 were as follows:																																																
<table><tr><th colspan="2">Security Type / Issuer</th><th colspan="2">Fair Value</th></tr><tr><th></th><th></th><th>2015</th><th>2014</th></tr><tr><td colspan="2">Federal Agency Fixed Income Securities</td><td colspan="2">(Thousands)</td></tr><tr><td>Federal Home Loan Bank</td><td>\$</td><td>917,423</td><td>\$ 597,048</td></tr><tr><td>Federal National Mortgage Association</td><td></td><td>210,528</td><td>334,680</td></tr><tr><td>Federal Farm Credit Bank</td><td></td><td>339,001</td><td>319,420</td></tr><tr><td>Federal Home Loan Mortgage Corp</td><td></td><td>333,923</td><td>225,405</td></tr></table>					Security Type / Issuer		Fair Value				2015	2014	Federal Agency Fixed Income Securities		(Thousands)		Federal Home Loan Bank	\$	917,423	\$ 597,048	Federal National Mortgage Association		210,528	334,680	Federal Farm Credit Bank		339,001	319,420	Federal Home Loan Mortgage Corp		333,923	225,405																	
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Federal Farm Credit Bank		339,001	319,420																																														
Federal Home Loan Mortgage Corp		333,923	225,405																																														
Interest Rate Risk - Risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates.	The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations. The following table shows the distribution of the Authority's investments by maturity at December 31, 2015 and 2014:																																																
<table><tr><th></th><th colspan="2">2015</th><th colspan="2">2014</th></tr><tr><th>Investment Type:</th><th>Fair Value (Thousands)</th><th>Weighted Average Maturity (Years)</th><th>Fair Value (Thousands)</th><th>Weighted Average Maturity (Years)</th></tr><tr><td>Certificates of Deposits</td><td>\$ 1,450</td><td>0.21</td><td>\$ 1,450</td><td>0.21</td></tr><tr><td>Federal Agency Discount Notes</td><td>413,582</td><td>0.18</td><td>465,622</td><td>0.18</td></tr><tr><td>Federal Agency Securities</td><td>1,412,756</td><td>2.18</td><td>1,036,008</td><td>2.32</td></tr><tr><td>Repurchase Agreements</td><td>98,910</td><td>0.01</td><td>304,118</td><td>0.01</td></tr><tr><td>U.S. Treasury Notes and Strips</td><td>114,243</td><td>11.37</td><td>45,601</td><td>7.43</td></tr><tr><td>Total</td><td>\$ 2,040,941</td><td></td><td>\$ 1,852,799</td><td></td></tr><tr><td>Portfolio Weighted Average Maturity</td><td></td><td>2.14</td><td></td><td>1.45</td></tr></table>						2015		2014		Investment Type:	Fair Value (Thousands)	Weighted Average Maturity (Years)	Fair Value (Thousands)	Weighted Average Maturity (Years)	Certificates of Deposits	\$ 1,450	0.21	\$ 1,450	0.21	Federal Agency Discount Notes	413,582	0.18	465,622	0.18	Federal Agency Securities	1,412,756	2.18	1,036,008	2.32	Repurchase Agreements	98,910	0.01	304,118	0.01	U.S. Treasury Notes and Strips	114,243	11.37	45,601	7.43	Total	\$ 2,040,941		\$ 1,852,799		Portfolio Weighted Average Maturity		2.14		1.45
	2015		2014																																														
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Total	\$ 2,040,941		\$ 1,852,799																																														
Portfolio Weighted Average Maturity		2.14		1.45																																													
The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the Nuclear Decommissioning Trust and Nuclear Decommissioning Fund. Together these accounts hold \$44.8 million par in U.S. Treasury Strips ranging in maturity from June 15, 2016 to May 15, 2039. The accounts also hold \$58.0 million par in government agency zero coupon securities in the two portfolios ranging in maturity from June 1, 2017 to April 15, 2030. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these portfolios. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed any earlier than 2043. The Authority has no other investments that are highly sensitive to interest rate fluctuations.																																																	
Foreign Currency Risk - Risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value.	The Authority is not authorized to invest in foreign currency and therefore has no exposure.																																																

NOTE 5 – LONG -TERM DEBT

Debt Outstanding

The Authority's long-term debt at December 31, 2015 and 2014 consisted of the following:

	2015	2014	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2055)				
2004 Taxable Series B	\$ 0	\$ 3,250	N/A	N/A
2004 Series M (4)	18,382	30,380	4.375-5.00	100/Accreted Value
2005 Refunding Series A	17,705	105,265	5.50	100
2005 Refunding Series B	0	217,065	N/A	N/A
2005 Refunding Series C	0	78,150	N/A	N/A
2005 Series M (4)	12,901	12,836	4.00-4.35	100/Accreted Value
2006 Tax-exempt Series A	0	13,370	N/A	N/A
2006 Taxable Series B	0	31,250	N/A	N/A
2006 Series M (4)	7,983	7,881	4.00-4.20	100/Accreted Value
2006 Refunding Series C	72,235	91,820	4.50-5.00	100
2007 Series A	75,885	114,400	5.00	100
2007 Refunding Series B	50,600	62,760	5.00	Non-callable
2008 Tax-exempt Series A	278,950	376,985	5.375-5.75	100
2008 Taxable Series B	25,000	25,000	8.368	P&I Plus Make-Whole Premium
2008 Series M (4)	21,233	21,049	3.80-4.80	100/Accreted Value
2009 Tax-exempt Refunding Series A	82,435	83,535	3.00-5.00	100
2009 Tax-exempt Series B	112,210	144,875	5.00-5.25	100
2009 Taxable Series C	84,695	86,895	4.82-6.224	P&I Plus Make-Whole Premium
2009 Tax-exempt Series E	100,000	100,000	4.75-5.00	100
2009 Taxable Series F	100,000	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series M1 (4)	26,278	27,991	3.50-4.30	100/Accreted Value
2010 Refunding Series B	161,460	190,905	3.00-5.00	100
2010 Series M2 (4)	15,523	17,402	2.875-3.875	100/Accreted Value
2010 Series C (Build America Bonds) (3)	360,000	360,000	6.454	P&I Plus Make-Whole Premium
2011 Series M1 (4)	26,801	26,781	2.00-4.80	100/Accreted Value
2011 Refunding Series B	267,615	279,600	4.00-5.00	Non-callable
2011 Refunding Series C	135,855	135,855	4.375-5.00	100
2011 Series M2 (4)	22,023	21,922	1.40-4.20	100/Accreted Value
2012 Refunding Series A	86,500	92,985	3.00-5.00	100
2012 Refunding Series B	21,200	23,200	5.00	Non-callable
2012 Refunding Series C	70,500	80,120	5.00	Non-callable
2012 Tax-exempt Series D	298,785	298,785	3.50-5.00	100
2012 Taxable Series E	262,830	262,830	3.572-4.551	P&I Plus Make-Whole Premium
2012 Series M1 (4)	20,855	21,055	1.40-4.00	100/Accreted Value
2012 Series M2 (4)	18,120	18,149	1.10-3.70	100/Accreted Value
2013 Series M1 (4)	23,276	23,327	1.30-3.90	100/Accreted Value
2013 Tax-exempt Series A	252,655	252,655	5.00-5.75	100
2013 Tax-exempt Refunding Series B	388,730	388,730	5.00-5.125	100
2013 Taxable Series C	250,000	250,000	5.784	P&I Plus Make-Whole Premium
2013 Taxable Series D (LIBOR Index Bonds)	0	100,000	N/A	N/A
2013 Tax-exempt Series E	506,765	506,765	5.00-5.50	100

	2015	2014	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
2014 Series M1 (4)	39,701	39,764	1.75-4.30	100/Accreted Value
2014 Tax-exempt Series A	600,000	600,000	2.50-6.45	100
2014 Tax-exempt Refunding Series B	42,275	42,275	5.00	100
2014 Tax-exempt Refunding Series C	704,525	704,525	3.00-5.50	100
2014 Taxable Refunding Series D	31,795	31,795	2.906-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	598,960	0	3.00-5.00	100
2015 Tax-exempt Refunding Series B	64,870	0	5.00	Non-callable
2015 Series M1 (4)	36,294	0	1.75-3.85	100/Accreted Value
2015 Tax-exempt Refunding Series C	270,170	0	5.00	Non-callable
2015 Taxable Series D	169,657	0	4.77	P&I Plus Make-Whole Premium
2015 Tax-exempt Series E	300,000	0	5.25	100
Total Revenue Obligations	7,134,232	6,504,182		
Other Long-Term Obligations: (mature through 2016)	0	44,956		
Less: Current Portion - Long-term Debt	172,896	149,689		
Total Long-term Debt - (Net of current portion)	\$ 6,961,336	\$ 6,399,449		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2015.

(2) Call Price may only apply to certain maturities outstanding at December 31, 2015.

(3) These bonds were issued as "Build America Bonds" under the American Recovery and Reinvestment Act of 2009 and are eligible to receive an interest subsidy payment from the United States Department of Treasury in an amount up to 35% of interest payable on the bonds.

(4) Includes Current Interest Bearing Bonds (CIBS) and Capital Appreciation Bonds (CABS).

Changes in Long-Term Debt

Long-term debt (LTD) activity for the years ended December 31, 2015 and 2014 was as follows:

	Gross LTD Beginning Balances	Increases	Decreases	Gross LTD Ending Balances	Current Portion LTD	Total LTD (Net of Current Portion)	Unamortized Debt Discounts and Premiums	LTD-Net Ending Balances
YEAR 2015 (Thousands)								
Other Long-Term Obligations	\$ 44,956	\$ 0	\$ (44,956)	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Revenue Obligations	6,504,182	1,442,855	(812,805)	7,134,232	172,896	6,961,336	345,133	7,306,469
Totals	\$ 6,549,138	\$ 1,442,855	\$ (857,761)	\$ 7,134,232	\$ 172,896	\$ 6,961,336	\$ 345,133	\$ 7,306,469
YEAR 2014 (Thousands)								
Capitalized Lease Obligations	\$ 244	\$ 0	\$ (244)	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Other Long-Term Obligations	44,956	0	0	44,956	0	44,956	(467)	44,489
Revenue Obligations	6,402,292	1,420,895	(1,319,005)	6,504,182	149,689	6,354,493	240,180	6,594,673
Totals	\$ 6,447,492	\$ 1,420,895	\$ (1,319,249)	\$ 6,549,138	\$ 149,689	\$ 6,399,449	\$ 239,713	\$ 6,639,162

Summary of Long-Term Principal and Interest

Maturities and projected interest payments of long-term debt are as follows:

	PRINCIPAL (1)	INTEREST (1)	TOTAL (1)
Year Ending December 31,	(Thousands)		
2016	\$ 158,347	\$ 354,198	\$ 512,545
2017	116,707	348,640	465,347
2018	158,943	342,833	501,776
2019	212,131	335,115	547,246
2020	192,136	327,029	519,165
2021-2025	782,245	1,519,224	2,301,469
2026-2030	711,129	1,364,824	2,075,953
2031-2035	788,547	1,188,648	1,977,195
2036-2040	888,335	960,887	1,849,222
2041-2045	1,045,307	730,756	1,776,063
2046-2050	1,241,345	416,409	1,657,754
2051-2055	839,060	120,623	959,683
Total	\$ 7,134,232	\$ 8,009,186	\$ 15,143,418

(1) Includes Revenue Obligations only - no other applicable debt.

Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds).

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Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2015 are as follows:

Refunding Description	Refunded Debt		Outstanding	Original Loss	Unamortized Loss
	(Thousands)			(Thousands)	
Cash Defeasance	\$	20,000	1982 Series A	\$ 2,763	\$ 479
Commercial Paper	\$	76,050	1973 Series		
		105,605	1977 Series		
		81,420	1978 Series	2,099	6
2006 Refunding Series C	\$	105,005	1999 Series A		
		10,000	2002 Series B	7,054	518
2007 Refunding Series B	\$	105,370	1997 Refunding Series A	8,832	1,047
2009 Refunding Series A	\$	99,515	1997 Refunding Series A		
		20,125	1998 Refunding Series B	8,707	5,265
2010 Refunding Series B	\$	30,430	2001 Series A		
		118,600	2002 Series B		
		84,780	2002 Refunding Series D	22,954	8,779
2011 Refunding Series B	\$	8,990	2002 Refunding Series D		
		291,825	2004 Series A	23,287	10,111
2011 Refunding Series C	\$	134,715	2002 Series B		
		5,160	2007 Series A	4,362	3,586
2012 Refunding Series A	\$	73,535	2003 Refunding Series A		
		34,160	2004 Series A	12,206	7,394
Feb 2012 Defeasance	\$	5,615	2003 Refunding Series A	749	601
2013 Refunding Series B	\$	209,426	2003 Refunding Series A		
		7,070	2004 Series A		
		5,000	2006 Series A		
		6,565	2007 Series A		
		82,605	2008 Series B		
		1,125	2009 Series B		
		30,158	2011 Series A (LIBOR Index)		
		2,040	2012 Series D	14,446	13,184
2013 Refunding Series C	\$	35,584	2003 Refunding Series A		
		97,695	2008 Series B	4,601	4,095

Summary of Refunded and Defeased Debt and Unamortized Losses (continued)

Refunding Description		Refunded Debt	Outstanding	Original Loss	Unamortized Loss
		(Thousands)		(Thousands)	
2014 Refunding Series C & Taxable Refunding Series D	\$	10,870 2003 Refunding Series A 11,395 2005 Refunding Series A 419,105 2006 Series A 10,385 2006 Refunding Series C 175,775 2007 Series A 4,230 2007 Refunding Series B 15,000 2008 Series A 15,200 2009 Series B 12,920 2010 Refunding Series B 3,100 2011 Refunding Series B 5,625 2012 Refunding Series A 2,000 2012 Refunding Series B 15,185 2012 Refunding Series C 11,335 2012 Series D 18,185 2013 Taxable Series D (LIBOR Index) 44,075 Expansion Bond Refunding CP	641,580	32,936	31,123
Nov 2014 Defeasance	\$	331,815 2013 Taxable Series D (LIBOR Index)	0	1,097	344
2015 Refunding Series A	\$	13,370 2006 Series A 32,750 2007 Series A 93,035 2008 Series A 30,765 2009 Series B	169,920	21,487	19,616
2015 Refunding Series B	\$	78,150 2005 Refunding Series C	0	4,987	4,567
2015 Refunding Series C	\$	87,560 2005 Refunding Series A 217,065 2005 Refunding Series B	304,625	24,366	23,128
2015 Series E	\$	100,000 Barclays Revolving Credit Agreement	0	89	89
Total			\$ 1,116,125	\$ 197,022	\$ 133,932

Analysis of Prior Year Current Portion of Long-term Debt

As a part of its long-term capital structure plan, the Authority will be involved in a multi-year refinancing plan. As a result, each year certain maturities classified as current portion of long-term debt may be refinanced in the subsequent year prior to the maturity date. Below is an analysis of the 2014 current portion of long-term debt showing the amounts paid as debt service in 2015 and the amount refinanced. The remaining amount represents five percent of the original principal for all outstanding minibond issues.

Analysis of December 31, 2014 Current Portion of Long-term Debt:		(Thousands)
Principal debt service paid from 2015 Revenues		\$ 136,058
Refinanced and other:		
2015 maturities refinanced		0
5% current portion requirement for original minibond issue amount (1)		13,631
Total		\$ 149,689

(1) Represents five percent annual cap on the requirement related to put features on all outstanding minibond issues. This is an accounting entry only and does not impact debt service.

An analysis of the \$133,671 current portion of long-term debt at December 31, 2013 showed that \$94,004 was debt service paid from 2014 revenues and \$28,015 of maturities were refinanced. The remaining \$11,652 represented five percent of the original principal for outstanding minibond issues.

Reconciliations of Interest Charges

Years Ended December 31,	2015	2014
	(Thousands)	
<i>Reconciliation of interest cost to interest expense:</i>		
Total interest cost	\$ 344,584	\$ 317,159
Capitalized interest	(43,481)	(31,385)
Deferred interest expense	(18,539)	(14,652)
Interest charged to fuel expense	0	(2,133)
Total interest expense on long-term debt	\$ 282,564	\$ 268,989
<i>Reconciliation of interest cost to interest payments:</i>		
Total interest cost	\$ 344,584	\$ 317,159
Accrued interest-current year	(67,378)	(79,061)
Accrued interest-prior year	79,061	100,159
Interest released by refundings	(6,802)	(12,819)
Accretion on capital appreciation minibonds	(3,062)	(2,881)
Adjustment for prior year interest expense	0	(93)
Total interest payments on long-term debt	\$ 346,403	\$ 322,464

Debt Service Coverage

Years Ended December 31,	2015	2014
	(Thousands)	
Operating revenues	\$ 1,879,553	\$ 1,997,347
Interest and investment revenue	9,207	29,023
Total revenues and income	1,888,760	2,026,370
Operating expenses	(1,502,488)	(1,619,224)
Depreciation	176,039	173,743
Total expenses	(1,326,449)	(1,445,481)
Funds available for debt service prior to distribution to the State	562,311	580,889
Distribution to the State	(20,116)	(20,659)
Funds available for debt service after distribution to the State	\$ 542,195	\$ 560,230
<i>Debt Service on Accrual Basis:</i>		
Principal on long-term debt	\$ 104,555	\$ 108,851
Interest on long-term debt	282,564	268,989
Long-term debt service paid from Revenues	387,119	377,840
Commercial paper and other principal and interest	16,146	7,453
Total debt service paid from Revenues	\$ 403,265	\$ 385,293
<i>Debt Service Coverage Ratio:</i>		
<i>Excluding commercial paper and other:</i>		
Prior to distribution to the State	1.45	1.53
After distribution to the State	1.40	1.48
<i>Including commercial paper and other:</i>		
Prior to distribution to the State	1.39	1.50
After distribution to the State	1.34	1.45

Note: Year 2014 was recalculated using the 2015 approved methodology.

Fair Value of Debt Outstanding

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was \$8.5 billion and \$7.7 billion at December 31, 2015 and 2014, respectively.

2015 Bond Market Transactions

Bond market transactions for the year ended December 31, 2015 were as follows:

Revenue Obligations, 2015 Series M1	Par Amount:	\$36,136,600	Date Authorized:	May 1, 2015
Summary: - Issued Current Interest Bearing Bonds in \$500 denominations and Capital Appreciation Bonds in \$200 denominations - Issued directly by the Authority to residents of the State, customers of the Authority, members of electric cooperatives organized under the laws of the State and electric customers of the Bamberg Board of Public Works and the City of Georgetown - Interest rates range from 1.75 percent in 2020 and 3.85 percent in 2035				
Revenue Obligations, 2015 Tax-exempt Refunding and Improvement Series A, Refunding Series B, Refunding Series C and Taxable Series D	Par Amount:	\$1,103,657,000	Date Authorized:	February 13, 2015
Summary: - Series A and D were issued on February 26, 2015, Series B was issued on April 7, 2015 and Series C was issued on October 6, 2015 at an aggregate all-in true interest cost of 4.10 percent - Maturities between December 1, 2016 and December 1, 2055				
Revenue Obligations, 2015 Tax-exempt Series E	Par Amount:	\$300,000,000	Date Authorized:	December 7, 2015
Summary: - Issued December 22, 2015 at an aggregate all-in true interest cost of 4.74 percent - Bond matures on December 1, 2055				

Debt Covenant Compliance

As of December 31, 2015 and 2014, the Authority was in compliance with all debt covenants. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

- (1) the Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements and all costs of operation and maintenance of the Authority's Electric and Water Systems and all necessary repairs, replacements and renewals thereof; and
- (2) the Authority is restricted from issuing additional parity bonds unless certain conditions are met.

All Authority debt (Electric and Water Systems) issued pursuant to the Revenue Obligation Resolution is payable solely from and secured by a lien upon and pledge of the applicable Electric and Water Revenues of the Authority. Revenue Obligations are senior to:

- (1) payment of expenses for operating and maintaining the Systems;
- (2) payments for debt service on capitalized leases;
- (3) payments for debt service on commercial paper; and
- (4) payments made into the Capital Improvement Fund.

Bond Outstanding Summary

As of December 31,	2015	2014
Outstanding Revenue Obligations	\$7.1 Billion	\$6.5 Billion
Estimated remaining interest payments	\$8.0 Billion	\$6.8 Billion
Issuance years (inclusive)	2005 through 2015	2004 through 2014
Maturity years (inclusive)	2016 through 2055	2015 through 2054

NOTE 6 – VARIABLE RATE DEBT

The Board has authorized the issuance of variable rate debt not to exceed 20 percent of the aggregate Authority debt outstanding (including commercial paper) as of the last day of the most recent fiscal year for which audited financial statements of the Authority are available. At December 31, 2015, eight percent of the Authority's aggregate debt outstanding was variable rate. The lien and pledge of Revenues securing variable rate debt issued as Revenue Obligations is senior to that securing commercial paper.

Commercial paper is issued for valid corporate purposes with a term not to exceed 270 days. The information related to commercial paper was as follows:

Years Ended December 31,	2015	2014
Commercial paper outstanding (000's)	\$ 597,520	\$ 410,139
Effective interest rate (at December 31)	0.25%	0.15%
Average annual amount outstanding (000's)	\$ 474,479	\$ 341,974
Average maturity	37 Days	51 Days
Average annual effective interest rate	0.18%	0.13%

As of December 31, 2015 the Authority had Revolving Credit Agreements with Bank of America, N.A., J.P. Morgan Chase Bank, N.A., TD Bank, N.A., U.S. Bank, N.A., and Wells Fargo Bank, N.A. totaling \$750.0 million. As of December 31, 2014 the Authority had Revolving Credit Agreements with Barclays Bank PLC, J.P. Morgan Chase Bank, N.A., TD Bank, N.A., U.S. Bank, N.A., and Wells Fargo Bank, N.A. totaling \$800.0 million. These agreements are used to support the Authority's issuance of commercial paper. There were no borrowings under the agreements during 2015 or 2014.

As of December 31, 2015 the Authority had a Revolving Credit Agreement (Direct Purchase Revolving Credit Agreement) with Barclays Bank PLC for \$200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on September 22, 2015 and expires November 27, 2019. On November 12, 2015, the Authority secured a \$100.0 million loan under the Direct Purchase Revolving Credit Agreement and used these proceeds to pay off the \$100.0 million 2013 Taxable Series D (LIBOR Index Bonds). The Authority fully paid off this Direct Purchase Revolving Credit loan with proceeds raised through the issuance of the 2015 Tax-Exempt Series E Bonds which were issued on December 22, 2015.

NOTE 7 – SUMMER NUCLEAR STATION

Nuclear Unit 1 - The Authority and SCE&G are parties to a joint ownership agreement providing that the Authority and SCE&G shall own Unit 1 at the Summer Nuclear Station with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. SCE&G is solely responsible for the design, construction, budgeting, management, operation, maintenance and decommissioning of Unit 1 and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. In 2004, the NRC granted a twenty-year extension to the operating license for Unit 1, extending it to August 6, 2042.

Authority's Share of Summer Nuclear - Unit 1			
Years Ended December 31,	2015	2014	
	(Millions)		
Plant balances before depreciation	\$ 540.3	\$ 521.3	
Accumulated depreciation	334.8	332.9	
Operation & maintenance expense	85.5	83.9	

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. Through April 2014, costs included a component for disposal of spent nuclear fuel; however, in May 2015, the Department of Energy (DOE) suspended the collection of spent fuel disposal fees. Fuel amortization and disposal fees are included in fuel expense and recovered through the Authority's rates.

In 2002, SCE&G commenced a re-racking project of the on-site spent fuel pool. The new pool storage capability will permit full core off-load through 2017. SCE&G has signed contracts with HOLTEC International, The Shaw Group, Inc. and Westinghouse Electric Company, Inc. (Westinghouse) to build a licensed Independent Spent Fuel Storage Installation (ISFSI) to commence receiving fuel in 2016. Because of DOE's failure to meet its obligation to dispose of spent fuel, SCE&G and the Authority are being reimbursed by DOE for ISFSI project costs. The Authority expects this reimbursement will equal approximately 75 percent of total project cost. Through December 31, 2015, reimbursements received equal 61 percent of total project expenditures.

The NRC requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable NRC regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2012 and the NRC's imposed minimum requirement. Based on these estimates, the Authority's one-third share of the estimated decommissioning costs of Unit 1 equals approximately \$315.1 million in 2012 dollars. As deposits are made, the Authority debits FERC account 532 - Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates.

Based on current decommissioning cost estimates, these funds, which totaled approximately \$210.5 million (adjusted to market) at December 31, 2015, along with future deposits into the external decommissioning trust and internal fund, investment earnings and projected DOE reimbursement of spent fuel storage costs, are estimated to provide sufficient funds for the Authority's one-third share of the total decommissioning cost.

Nuclear Units 2 and 3 - The Authority and SCE&G are constructing and planning to operate two additional nuclear generating units at Summer Nuclear Station (Units 2 and 3) and submitted an application to the NRC in March 2008 for a combined Construction and Operating License (COL) for each of the two new units. On May 22, 2008, the Authority's Board authorized the Authority to execute a Limited Agency Agreement appointing SCE&G to act as the Authority's agent in connection with the performance of an Engineering, Procurement and Construction (EPC) Agreement. On May 23, 2008, SCE&G, acting for itself and as agent for the Authority, entered into an EPC Agreement with Westinghouse and Stone & Webster, Inc., (a subsidiary of The Shaw Group, Inc.), for the engineering, procurement and construction of two 1,117 MW nuclear generating units. Chicago Bridge & Iron Company acquired The Shaw Group, Inc. in February 2013.

On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement. Among other things, the Design and Construction Agreement allows either or both parties to withdraw from the project under certain circumstances. Also on October 20, 2011, the Authority and SCE&G entered into an Operating and Decommissioning Agreement with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement define the conditions under which the Authority or SCE&G may convey an undivided ownership interest in the new units to a third party. Together the Design and Construction Agreement and the Operating and Decommissioning Agreement provide for a 45 percent ownership interest by the Authority in each of the two new units and replace the Amended and Restated Bridge Agreement which had governed the relationship between the Authority and SCE&G.

The Authority received the COLs on March 30, 2012. On April 5, 2012, the Authority's Board authorized the Authority to expend up to \$4.9 billion to fund the Authority's share of the EPC Agreement and associated Owner's Costs to complete the project. On October 23, 2015, the Authority's Board authorized the President and CEO of the Authority to execute a Limited Agency Agreement that appointed SCE&G to act as the Authority's agent in connection with an October 2015 Amendment to the EPC Agreement.

On October 27, 2015, the EPC Agreement was amended ("October 2015 Amendment"). The October 2015 Amendment became effective on December 31, 2015 upon the consummation of the acquisition by Westinghouse of the stock of Stone & Webster from CB&I. Stone & Webster will continue to be a member of the Consortium as a subsidiary of Westinghouse instead of CB&I. Westinghouse has engaged Fluor Corporation as a subcontracted construction manager. Among other things, the October 2015 Amendment (i) revises the guaranteed substantial completion dates of Units 2 and 3 to August 31, 2019 and 2020, respectively, and (ii) provides the Authority and SCE&G an irrevocable option, until November 1, 2016 and subject to regulatory approvals, to further amend the EPC Agreement to fix the total amount to be paid to the Consortium for its entire scope of work on the project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at \$6.082 billion (Authority's 45 percent portion being approximately \$2.737 billion).

As part of its capital improvement program, the Authority has evaluated its level of participation in the new units. Due to developments since initiation of the project, the Authority has taken actions necessary to reduce its 45 percent ownership interest. In January 2014, the Authority entered into an agreement whereby SCE&G will purchase from the Authority an additional five percent interest in the project. Under the terms of the agreement, SCE&G will own 60 percent of the new nuclear units and the Authority, 40 percent. The five percent ownership interest will be acquired in three stages, with one percent to be acquired at the commercial operation date of the first new nuclear unit, an additional two percent to be acquired no later than the first anniversary of such commercial operation date, and the final two percent to be acquired no later than the second anniversary of such commercial operation date. The purchase price will be equal to the Authority's actual cost, including financing costs, of the percentage conveyed as of the date of the conveyance. The agreement will not impact the payment obligation for the full 45 percent ownership during construction. In December 2015, the Authority and SCE&G executed the Purchase and Sale Agreement for SCE&G's purchase from the Authority of an additional five percent interest in the project as described above. Beginning 2011, the Authority deferred a portion of interest expense representing the amount related to the assumed ownership reduction. In 2013, the Authority continued deferring and began capitalizing portions of related interest expense based on revised ownership assumptions.

NOTE 8 – LEASES

The Authority made the final payment related to the capital lease contracts with Central on November 26, 2014. There are currently no capital leases.

Information related to property under operating lease payments follows:

Years Ended December 31,	2015	2014
	(Millions)	
Operating lease payments (1)	\$ 2.8	\$ 2.1
(1) Includes periodic leased coal car expenses which are initially reflected in fuel inventory and subsequently reported in fuel expense based on tons burned.		
Expiration term of current coal car leases: (2)	December 2015 and March 2016	
(2) The maximum amount due for coal car leases for 2015 is \$1,038,000.		

Hydroelectric generating facility lease:

- Automatically extended for five-year periods
- May be terminated by either party by giving a two-year notice
- Obligation is \$600,000 per year plus operating expenses

NOTE 9 – CONTRACTS WITH ELECTRIC POWER COOPERATIVES

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement (the Coordination Agreement). Under this agreement, the Authority is the predominant supplier of energy needs for Central, excluding amounts supplied by others to five of its member cooperatives located in the upper part of the State which is further described below, energy Central receives from the Southeastern Power Administration (SEPA), minimal amounts provided by Broad River Electric Cooperative's ownership interest in a small run of the river hydroelectric plant and negligible amounts purchased from others.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to them through the Coordination Agreement. Any differences found as a result of this process are accrued if they are probable and estimable. To the extent that differences arise, prospective adjustments are made to the cost of service and are reflected in operating revenues in the accompanying Combined Statements of Revenues, Expenses and Changes in Net Position. Such adjustments in 2015 and 2014 were not material to the Authority's overall operating revenue.

In September 2009, the Authority and Central entered into an agreement which, among other things, would permit Central to purchase the electric power and energy requirements necessary to serve five of its member cooperatives located in the upper part of the State that were formerly members of Saluda: Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc. (the Upstate Load) from a supplier other than the Authority.

The Upstate Load began transitioning to the new supplier in 2013. The transition will continue through 2019 and will amount to approximately 900 MW.

In 2013, the Central and Authority Boards, respectively, approved an Amendment to the Central Agreement (Agreement). As part of this Central agreed to extend their rights to terminate the agreement until December 31, 2058. The Agreement includes a 10-year rolling notice provision. For a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. The Agreement provides for closer cooperation on planning of future resources, gives Central the ability to “opt-out” of future generation resources, and provides for cost recovery of all resources completed or under construction as of the amendment effective date, including Summer Nuclear Units 2 and 3.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

Budget – The Authority’s 2016 three-year capital budget is as follows:

Years Ending December 31,	2016	2017	2018
		(Millions)	
Summer Nuclear Units 2 and 3 (1)	597.0	601.5	494.8
General improvements	246.2	221.6	230.9
Environmental compliance (2)	\$ 68.2	\$ 114.4	\$ 136.4
Total capital budget (3)	\$ 911.4	\$ 937.5	\$ 862.1

Budget Assumptions:

- (1) Construction cash flows for 2015 and the 2016-2018 budgets reflect 45 percent ownership. Subsequent cash flows will be reduced in accordance with the projected ownership sale date. Total estimated project cost including transmission is \$4,565 million.
- (2) Includes ash pond closure and remediation.
- (3) Will be financed by internally generated funds, taxable and tax-exempt debt.

Purchase Commitments – The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2015. The disclosure of minimum obligations (including market re-opener contracts) shown below is based on the Authority’s contract rates and represents management’s best estimate of future expenditures under long-term arrangements.

Years Ending December 31,	With Re-openers (All Tons) (1)	Without Re-openers (Fixed Tons) (2)
	(Thousands)	
2016	\$ 219,924	\$ 219,924
2017	130,750	103,250
2018	122,250	122,250
2019	59,250	59,250
2020	0	0
Total	\$ 532,174	\$ 504,674

(1) Includes tons which the Authority can elect not to receive.

(2) Includes tons which the Authority must receive.

The Authority has the following outstanding obligations under existing long-term capacity and purchased power contracts as of December 31, 2015:

Contracts with Minimum Fixed Payment Obligations			
Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	20 Years	\$ 52.0
1	2016	1 Year	26.7
1	2016	1 Year	12.8
1	2016	1 Year	19.6

Contracts with Power Receipt and Payment Obligations (1)			
Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	10 Years	\$ 194.6
2	2013	28 Years	631.8
1	2013	18 Years	7.8
1	2016	25 Years	437.1

(1) Payment required upon receipt of power. Assumes no change in indices or escalation.

The Authority purchases network integration transmission service through transmission agreements with Duke Energy Corporation and SCE&G. This network transmission service is used to serve the Upstate Load and other wholesale customers who are not in the Authority's direct-served territory; the Authority is obligated for costs associated with these transmission agreements. The table below shows the transmission obligations in 2016 and the total transmission obligations for 2017-2027. Note that the transmission obligations associated with the Upstate Load will end in 2019 (concurrent with the end of the transition period), at which time the Authority will no longer be responsible for purchasing transmission service for the Upstate Load served by the new supplier. The remaining wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations			
		2016	2017-2027
		(Thousands)	
Upstate Load(1)	\$	4,656	\$ 4,154
Other Customers		2,929	15,068
Total	\$	7,585	\$ 19,222

(1) Obligation ends in 2019

CSX Transportation, Inc. (CSX) provides substantially all rail transportation service for the Authority's Cross and Winyah coal-fired generating stations. The Authority also interchanges with some short line railroads via CSX for the movement of coal as well. The CSX contract, effective January 1, 2011, and extended per amendment effective January 1, 2016, continues to apply a price per ton of coal moved, along with a mileage based fuel surcharge and minimum tonnage obligation.

The Authority has commitments for nuclear fuel, nuclear fuel conversion, enrichment and fabrication contracts for Summer Nuclear Units 1, 2 and 3. As of December 31, 2015, these contracts total approximately \$508.5 million over the next 22 years.

In 2010, the Authority amended the Rainey Generating Station Long-Term Parts and Long-Term Service Contract with General Electric International, Inc. (GEIL). In lieu of exercising its option to terminate the Contract for convenience and to pursue non original equipment manufactured parts and services, the Authority negotiated an amendment with reduced pricing for maintenance and fixed escalation. The contract provides a contract performance manager (CPM), initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators and combustion tuning for the gas turbines.

The amended contract value is approximately \$97.2 million, excluding escalation and adjustments for liquidated damages and bonuses. The contract term extends through the second major inspection for Rainey 1 (expected to be completed in 2018). Rainey 2A and 2B have reached the contract “performance end date.” The Authority’s estimated remaining commitment on the contract is \$25.6 million, including escalation, and the Authority is currently exploring options for these units, including a potential extension of the GEII contract. The Authority’s Board has approved recovery of contract expenditures on a straight-line basis over the term of the contract.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation (TRANSCO) to supply gas transportation needs for its Rainey Generating Station. This is a firm service agreement for the transportation of 80,000 decatherms per day.

Risk Management – The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks did not exceed commercial insurance coverage in 2015. Policies are subject to deductibles ranging from \$500 to \$2.0 million, with the exception of named storm losses which carry deductibles from \$2.0 million up to \$5.0 million. Also a \$1.4 million general liability self-insured layer exists between the Authority’s primary and excess liability policies. During 2015, there were minimal payments made for general liability claims.

The Authority is self-insured for auto, dental, worker’s compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of \$2.0 million per incident. Risk exposure for the dental plan is limited by plan provisions. Estimated exposure for worker’s compensation is based on an annual actuarial study using loss and exposure information valued as of June 30, 2015. In addition, there have been no third-party claims regarding environmental damages for 2015 or 2014.

Claim expenditures and liabilities are reported when it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. The amount of the self-insurance liabilities for auto, dental, worker’s compensation and environmental remediation is based on the best estimate available. Changes in the reported liability were as follows:

Years Ended December 31,	2015	2014
	(Thousands)	
Unpaid claims and claim expense at beginning of year	\$ 1,321	\$ 2,538
Incurred claims and claim adjustment expenses:		
Add: Provision for current year events	2,377	2,043
Less: Payments for current and prior years	2,219	3,260
Total unpaid claims and claim expenses at end of year	\$ 1,479	\$ 1,321

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. The State assumes all risks for the following:

- (1) claims of covered employees for health benefits covered through South Carolina Public Employee Benefit Authority (PEBA) Insurance Benefits; not applicable for worker’s compensation injuries; and
- (2) claims of covered employees for basic long-term disability and group life insurance benefits (PEBA Insurance Benefits and PEBA Retirement Benefits).

Employees elect health coverage through the State’s self-insured plans. However, additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State’s self-insured plan.

Nuclear Insurance – The maximum liability for public claims arising from any nuclear incident has been established at \$13.5 billion by the Price-Anderson Indemnification Act. This \$13.5 billion would be covered by nuclear liability insurance of \$375.0 million per reactor unit, with potential retrospective assessments of up to \$127.3 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed \$18.9 million per incident, per year). Based on its one-third interest in Summer Nuclear Unit 1, the Authority could be responsible for the maximum assessment of \$42.4 million, not to exceed approximately \$6.3 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC. Additionally, SCE&G and the Authority maintain, with Nuclear Electric Insurance Limited (NEIL), \$1.5 billion primary and \$1.25 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. SCE&G and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. In addition to the premiums paid on these policies, SCE&G and the Authority could also be assessed a retrospective premium, not to exceed ten times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be approximately \$7.3 million for the primary policy, \$2.3 million for the excess policies and \$1.8 million for the accidental outage policy.

SCE&G and the Authority maintain builder's risk insurance and marine cargo insurance for the Summer Nuclear Units 2 and 3 construction. The builder's risk policy provides coverage of \$2.75 billion accidental nuclear property damage with a sub-limit of \$500.0 million for accidental property damage that is caused by or results from any covered peril other than radioactive contamination resulting from nuclear reaction, nuclear radiation or the release of radioactive materials, with deductibles ranging from \$250,000 to \$5.0 million. This policy also carries a potential retrospective premium of approximately \$42.0 million. Based on the Authority's current 45 percent ownership interest, the Authority's maximum retrospective premium would be approximately \$18.9 million. The marine cargo/transit policy provides coverage of \$300.0 million, with deductibles ranging from \$25,000 to \$75,000.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage or cost increases for any periods through December 31, 2015.

Clean Air Act – The Authority endeavors to ensure that its facilities comply with applicable environmental regulations and standards.

In addition to the existing Clean Air Act (CAA) Federal Acid Rain Program, the Environmental Protection Agency (EPA) has promulgated and is implementing the Cross State Air Pollution Rule (CSAPR) for SO₂ and NO_x emissions, effective January 1, 2015.

CSAPR was EPA's replacement for the Clean Air Interstate Rule (CAIR). After going through the U.S. Court of Appeals process for the D.C. Circuit over the last several years, CSAPR is now in effect due to several court decisions in 2014. Emission budgets were applied beginning January 1, 2015 for the annual programs, and also started on May 1, 2015 for the ozone-season NO_x program. This rule is not expected to negatively impact Santee Cooper.

Currently, there are both legislative and regulatory efforts to reduce greenhouse gas emissions. The Authority continues to review proposed greenhouse gas regulations to assess potential impacts to its operations. In 2010, EPA finalized the Prevention of Significant Deterioration (PSD) Tailoring Rule for regulating greenhouse gases through the PSD permitting process under the existing CAA. EPA issued Best Available Control Technology (BACT) Guidance in 2010 for use under the rule effective July 1, 2011. In 2014, EPA proposed three separate rules for (1) new, (2) existing, and (3) modified and reconstructed Electric Generating Units (EGU). On August 3, 2015, EPA proposed a final rule to regulate carbon dioxide emissions from power plants. The final rule was published in the Federal Register on October 23rd and has major revisions that benefit South Carolina by allowing the use of new nuclear unit at Summer Nuclear for compliance for existing generation units. For new, modified, or existing units, the final rule appears to offer attainable limits for modified and reconstructed coal steam units as well as combined cycle gas generation. The rule requires partial carbon capture and storage for new coal-fired units. Santee Cooper is working to model how the final rule will impact Santee Cooper based on the current generation forecast. On February 9, 2016, the Supreme Court in a 5-4 vote granted an emergency stay of the EPA's rule for existing units. The stay will remain in effect through the review of the rule by the Court of Appeals for the District of Columbia Circuit and until the Supreme Court decides the matter, in the event that the losing side decides to appeal to the Supreme Court. This legal process could run into the middle of 2018.

In place of the vacated federal Clean Air Mercury Rule (CAMR), South Carolina utilities and DHEC finalized a Memorandum of Agreement (MOA) in which the Authority committed to install and certify mercury Continuous Emissions Monitoring Systems (CEMS) at a set of agreed-upon coal-fired units and collaborate with the South Carolina utilities and DHEC to provide support for a state-wide assessment evaluating the mercury deposition resulting from coal-fired power plants in South Carolina. In 2009, the mercury CEMS were installed at the specified Authority units and utilities began initial reporting. There are no cap and trade or emissions limitations requirements per the MOA.

Through the maximum achievable control technology (MACT) regulatory process, the EPA has proposed the Utility MACT regulations to reduce the emissions of mercury and other hazardous air pollutants (HAPs) from coal and oil-fired electric utility steam boilers. As a part of EPA rule development, the Authority participated in the EPA's mandatory Information Collection Request (ICR) for mercury and other HAPs for its coal-fired and oil-fired units. The ICR required facility and fuel information as well as stack testing at Cross, Winyah and Jefferies generating stations.

The proposed MACT rule was released in March 2011 with a public notice comment period. The Authority submitted comments to the proposed rule. The final MACT rule, renamed the Mercury and Air Toxics Standard (MATS) became effective April 16, 2012, with a compliance deadline for existing units of April 16, 2015. Santee Cooper applied for and received a compliance extension for its Cross and Winyah coal-fired EGUs for April 16, 2016 granted by DHEC and in accordance with the regulation. On June 29, 2015, the U.S. Supreme Court remanded MATS back to a lower court for EPA to consider costs for developing the emissions limits in MATS (EPA did not consider costs in determining the original limits in MATS). The lower court remanded the rule back to EPA for consideration of costs in December 2015. In November 2015, EPA proposed a supplemental finding that includes a consideration of costs would not alter EPA's previous determination that it is appropriate to regulate air toxins.

The MATS rule includes emissions limitations for mercury, acid gases and other HAPs from existing and new coal-fired and oil-fired electric utility steam units. This is EPA's first national standard to reduce mercury and other air toxics from coal-fired and oil-fired power plants.

On November 26, 2014, the U.S. EPA completed the federally mandated 5-year review of the national ambient air quality standards (NAAQS) and proposed a revised (more stringent) ground-level ozone standard range. This applies to both the primary (public health) and secondary (public welfare) standards. The 90-day public comment period began December 17, 2014. On October 1, 2015, EPA announced that the new NAAQS for ozone will be set at 70 parts per billion. This will apply to both the primary and secondary ozone standards. EPA projections, based on current monitoring networks, are that all counties in South Carolina will meet the revised standard by 2025 without taking additional action to reduce emissions.

Safe Drinking Water Act - The Authority continues to monitor regulatory issues impacting drinking water systems at the Authority's regional water systems, generating stations, substations and other auxiliary facilities. DHEC has regulatory authority of potable water systems in South Carolina under The State Primary Drinking Water Regulation, R.61-58; the Authority endeavors to manage its potable water systems in compliance with R.61-58.

Clean Water Act - The Clean Water Act (CWA) prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System (NPDES) permit program. DHEC has been delegated NPDES permitting authority by the EPA and administers the NPDES permit program for the State.

Wastewater discharges from the generating stations and the regional water plants are governed by NPDES permits issued by DHEC. Further, the storm water from the generating stations must be managed in accordance with the State's NPDES Industrial General Permit for storm water discharges. Storm water from construction activities must also be managed under the State's NPDES General Permit for storm water discharges from construction activity. The Authority constantly strives to operate in compliance with these permits.

The CWA, under Section 316(b), requires that cooling water intake structures (CWIS) reflect the best technology available for minimizing adverse environmental impacts, such as the impingement of fish and shellfish on the intake structures and the entrainment of eggs and larvae through cooling water systems. The EPA published the final rule under the CWA Section 316(b) on August 15, 2014, and the rule became effective October 15, 2014. The final rule contains some significant deviations from the proposed rule, such as an outline of seven compliance options and an extended reporting deadline. The Authority will continue to work with the regulatory agencies on implementation.

The EPA has regulations under the CWA relating to Spill Prevention Control and Counter-measures (SPCC). These regulations require that applicable facilities, which include generating stations, substations and auxiliary facilities, maintain SPCC plans to meet certain standards. The Authority continually works to be in compliance with these regulations.

The NPDES Steam Electric Effluent Limitation Guidelines (ELGs) rule became effective on January 4, 2016. It applies to all existing steam electric units greater than 50 MWs (other than oil-fired) and is to be phased in as soon as possible beginning November 1, 2018, but no later than December 31, 2023, via the reissuance of generating station NPDES Permits. New standards for new sources are also included. Since EPA promulgated best management practices (BMPs) to inspect active and inactive surface impoundments in the Coal Combustion Residuals rule, similar BMPs were not established in the ELGs, avoiding unnecessary duplication.

On June 29, 2015, EPA and the Corps of Engineers published the final rule that redefined “Waters of the U.S.” (WOTUS). The rule became effective on August 28, 2015. On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying the WOTUS rule nationwide pending completion of the Court’s review of the rule. The published final rule attempts to clarify which streams, wetlands, and other water bodies are subject to permitting and compliance requirements under the Clean Water Act. The final rule expands the federal jurisdiction under the Clean Water Act. For new construction or expansion projects there will be more water features regulated as Waters of the U.S. This will require additional permitting and mitigation enforcement.

Hazardous and Non-Hazardous Substances, Wastes and Byproducts – Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) provides for the reporting requirements to cover the release of hazardous substances into the environment. Additionally, the EPA regulations under the Toxic Substances Control Act (TSCA) impose stringent requirements for labeling, handling, storing and disposing of polychlorinated biphenyls (PCBs) and associated equipment.

Under the CERCLA and Superfund Amendments and Reauthorization Act (SARA), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. Moreover, under SARA, the Authority must comply with a program of emergency planning and a “Community Right-To-Know” program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions. The Authority endeavors to comply with the applicable provisions of TSCA, CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. The Authority strives to comply with all aspects of Resource Conservation and Recovery Act (RCRA) regarding appropriate disposal of chemical wastes.

The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, scrubber sludge and gypsum. These wastes, known as Coal Combustion Residuals (CCRs), are exempt from hazardous waste regulation under the RCRA. On April 17, 2015, the EPA published the rule to regulate CCRs as a RCRA Subtitle D, nonhazardous waste with an effective date of October 19, 2015. The rule establishes the following national minimum criteria for existing and new CCR landfills and surface impoundments:

- Location restrictions;
- Design and construction requirements;
- Operating criteria such as inspections, structural integrity evaluations and fugitive dust controls;
- Groundwater monitoring and corrective action;
- Closure requirements and post-closure care;
- Record keeping, notifications and Internet posting requirements.

No firm estimates relative to the cost of implementing this regulation have been made at this time since the rule is still under review. However, the Authority has budgeted \$325.0 million through 2019 for compliance purposes.

The Solid Waste Disposal Act and Energy Policy Act give EPA authority to regulate Underground Storage Tanks (USTs). EPA regulations concerning USTs are contained in 40 CFR Parts 280-282. DHEC has granted state program approval in 2002 and regulates USTs under R. 61-92, Part 280 dated 2008. This regulation provides requirements for the design, installation, operation, closure, release detection, reporting and corrective action and financial responsibility. The Authority’s corporate policy number 2-11-02 provides guidance for the proper management and monitoring of USTs for environmental and regulatory compliance.

At Cross Generating Station, construction of the Class 3 landfill was completed and certified to receive CCR waste on December 8, 2015. The Class 2 landfill received waste until December 31, 2015 and closure is scheduled for completion by June 30, 2016.

The Authority is in the process of retiring units and ancillary facilities at Grainger and Jefferies generating stations. The Authority plans to properly close ash ponds at these facilities by excavation and beneficial use. A closure plan for the Grainger Generating Station ash ponds has been approved by DHEC and closure through beneficial use is in progress. Development of a similar closure plan for Jefferies ash ponds is in progress. In addition, the Authority is planning to close the Grainger cooling pond in accordance with DHEC requirements.

The Authority received DHEC approval for plans to close the West Ash Pond and the Unit 2 slurry pond at Winyah Generating Station. Closure is in progress for both ponds.

Pollution Remediation Obligations — The Authority follows GASB 49 which addresses standards for pollution (including contamination) remediation obligations for activities such as site assessments and cleanups. GASB 49 does not include standards for pollution remediation obligations that are addressed elsewhere. Examples of obligations addressed in other standards include pollution prevention and control obligations for remediation activities required upon the retirement of an asset, such as ash pond closure and post-closure care and nuclear power plant decommissioning.

The Authority recorded \$40,000 for pollution remediation liabilities for each of the years ended December 31, 2015 and 2014. The method used to estimate the liabilities consists of weighting a range of possible estimated job cost amounts and calculating a weighted average cost. The weights and estimated costs are developed using professional engineering judgment acquired through years of estimating and completing many pollution remediation projects.

Homeland Security — The Department of Homeland Security (DHS) was established by the Homeland Security Act of 2002, a portion of which relates to anti-terrorism standards at facilities which store or process chemicals. The Authority has been proactive in striving to comply with these evolving regulations by conducting valid threat and risk assessments to the facilities regulated by the Chemical Facility Anti-Terrorism Standards (CFATS) program, also referred to as 6 CFR, Part 27. Once completed, the assessments (performed and coordinated by the Law Enforcement Division) become sensitive, federally controlled documents and are stored in accordance with all federal and state guidelines attendant to critical infrastructure information protection.

Legislative Matters — The Authority has been scheduled for review of its statutory compliance and strategic direction by a Joint Senate and House Oversight Committee pursuant to the South Carolina Restructuring Act of 2014, which requires the conduct of oversight studies of all state agencies at least every seven years. The Joint Oversight Committee held its initial meeting on January 5, 2016. The Authority's President and CEO Lonnie Carter gave an operational overview and responded to questions from committee members. The Authority will continue to assist the committee throughout the oversight process.

On December 10, 2015 there was prefiled in the South Carolina House of Representatives, by title only, a joint resolution (H 4541) dealing with a process for selling all or some noncontrolling percentage ownership interest in the Authority. Similar bills have been filed in the past, and the Authority will closely monitor this proposed legislation as the text of statutory language and other details become available.

Legal Matters — Except as noted below, there are no actions, suits, or governmental proceedings pending or, to the knowledge of the Authority, threatened before any court, administrative agency, arbitrator or governmental body which would, if determined adversely to the Authority, have a material adverse effect on its financial condition. However, even if determined adversely to the Authority, no such actions, suits, or governmental proceedings would have a material adverse effect on the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution.

Horry Electric Cooperative, Inc. (Horry Co-op) Suit. In May 2013, Horry Co-op, a member of Central, sued the Authority seeking indemnification for claims in a class action lawsuit brought against Horry Co-op by certain Horry customers. The customers allege mold damage to their homes was caused by vapor barriers installed in accordance with the Authority's energy efficiency recommendations. Horry Co-op's complaint alleges the Authority knew the vapor barrier could cause moisture problems but failed to disclose the information to Horry Co-op and failed to advise Horry Co-op that the vapor barrier should be a recommendation rather than a requirement. A settlement has been reached in the underlying class action lawsuit against Horry Co-op. The settlement provides for the establishment of two funds, totaling \$6.0 million dollars, to pay the claims of the class members. The Authority has been informed that as of the deadline for filing claims approximately \$1.4 million dollars in claims and attorney fees have been paid. The Authority filed a motion to dismiss the claims brought against it by Horry Co-op. On June 11, 2014, the Court dismissed the suit, ruling that the majority of the claims were dismissed with prejudice and that the claim for equitable indemnification was dismissed without prejudice. Horry Co-op has appealed the dismissal of the suit. The Authority cannot predict the outcome of the appeal. On October 20, 2014 the Authority was served with an additional complaint filed by Horry Co-op in Horry County. The complaint alleges a single cause of action for indemnity arising out of the same underlying factual allegations as the original complaint filed in May of 2013. The Authority has filed a motion to dismiss the complaint. The Authority cannot predict the outcome of this lawsuit.

Purported Class Action. The Authority has received an unfiled complaint which asserts a purported class action on behalf of the Authority's retail customers. The complaint contains a number of causes of action and allegations related to the Authority's decisions to construct and then to cancel construction of a coal-fired generation project in Florence County, SC. The Authority is evaluating the claim.

NOTE 11 – RETIREMENT PLANS

The South Carolina Public Employee Benefit Authority (PEBA), which was created July 1, 2012, administers the various retirement systems and retirement programs managed by its Retirement Division. PEBA has an 11-member Board of Directors, appointed by the Governor and General Assembly leadership, which serves as co-trustee and co-fiduciary of the systems and the trust funds. By law, the Budget and Control Board (restructured into the Department of Administration on July 1, 2015), which consists of five elected officials, also reviews certain PEBA Board decisions regarding the funding of the South Carolina Retirement Systems (SCRS) and serves as a co-trustee of the Systems in conducting that review.

PEBA issues a Comprehensive Annual Financial Report (CAFR) containing financial statements and required supplementary information for the Systems' Pension Trust Funds. The CAFR is publicly available through the Retirement Benefits' link on PEBA's website at www.peba.sc.gov, or a copy may be obtained by submitting a request to PEBA, PO Box 11960, Columbia, SC 29211-1960. PEBA is considered a division of the primary government of the state of South Carolina, and therefore, retirement trust fund financial information is also included in the comprehensive annual financial report of the state.

Plan Description – Substantially all Authority regular employees must participate in one of the components of the SCRS, a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws.

Benefit Provided – Vested employees (Class Two Members) who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. Vested employees (Class Three Members) who retire at age 65 or meet the “rule of 90 requirements” (i.e., the total of the member's age and the member's creditable service equals at least 90 years), are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service for Class Two Members and eight years for Class Three Members. Reduced retirement benefits are payable as early as age 60 with vested service or 55 with 25 years of service for Class Two Members. The SCRS also provides death and disability benefits. Benefits are established by State statute.

Effective January 1, 2001, Section 9-1-2210 of the South Carolina Code of Laws allowed SCRS employees eligible for service retirement to participate in the Teacher and Employee Retention Incentive (TERI) Program. TERI participants may retire and begin accumulating retirement benefits on a deferred basis without terminating employment for up to five years. Upon termination of employment or at the end of the TERI period, whichever is earlier, participants will begin receiving monthly service retirement benefits which include any cost of living adjustments granted during the TERI period. Because participants are considered retired during the TERI period, they do not earn service credit or disability retirement benefits. Effective July 1, 2005, TERI employees began “re-contributing” to the SCRS at the prevailing rate. However, no service credit is earned under the new regulations. The group life insurance of one times annual salary was re-established for TERI participants.

Effective July 1, 2012, the TERI program will close for Class Two members (members with effective date prior to July 1, 2012) on June 30, 2018, and it is not available to Class Three members (members with effective date on or after July 1, 2012). TERI will be phased out in a 5-4-3-2-1 format. Members who enter the TERI program after July 1, 2013, will not be eligible to participate for the full five years. TERI participation will end on June 30, 2018, regardless of when a member enters the program.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits and employee/employer contributions.

Effective July 1, 2002, new employees have a choice of the type of retirement plan in which to enroll. The State Optional Retirement Plan (State ORP) which is a defined contribution plan is an alternative to the SCRS retirement plan which is a defined benefit plan. The contribution amounts are the same, (8.16 percent employee cost and 10.91 percent employer cost); however, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 5.91 percent is contributed to the Retirement System. As of December 31, 2015, the Authority had 45 employees participating in the State ORP and consequently the related payments are not material.

Contributions - All employees are required by State statute to contribute to the SCRS at the prevailing rate, currently 8.16 percent. The Authority contributed 10.91 percent of the total payroll for SCRS retirement. For 2015, the Authority also contributed an additional 0.15 percent of total payroll for group life. The contribution requirements for the prior three years were as follows:

Years Ended December 31,	2015	2014	2013
	(Millions)		
From the Authority	\$ 14.8	\$ 13.9	\$ 13.3
From Employees	11.0	10.2	9.2

The Authority made 100 percent of the required contributions for each of the three years.

Liabilities, Expense and Deferred Outflows (Inflows) of Resources Related to Pensions - At December 31, 2015, the Authority reported a liability of \$286.3 million. This includes its share of the net pension liability from SCRS as well as pension liabilities associated with the supplemental executive retirement plans (SERP) noted under post-employment benefits, which were immaterial. The SCRS net pension liability was measured as of June 30, 2015 and determined by an actuarial valuation as of June 30, 2014. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of \$14.8 million paid to SCRS for the year ended June 30, 2015 relative to the actual contributions of \$1,188.1 million from all participating employers. At June 30, 2015, the Authority's proportionate share was 1.44 percent.

For the year ended December 31, 2015, the Authority recognized a pension expense of \$19.5 million, our proportionate share of the total pension expense. At December 31, 2015, the Authority reported deferred outflows (inflows) of resources related to pensions from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	\$ 4,863	\$ 487
Changes of assumptions	0	0
Net difference between projected and actual earnings on pension plan investments	17,562	15,726
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	22	1,202
Authority's contributions subsequent to the measurement date	7,537	0
Total	\$ 29,984	\$ 17,415

The Authority reported \$7.5 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2016. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years. The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2015. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2014, measurement date was 4.164 years for SCRS.

Year Ending December 31:	
	(Thousands)
2016	\$ 796
2017	796
2018	(867)
2019	4,307
2020	0
Total	\$ 5,032

Actuarial Assumptions – Actuarial valuations of the Authority involves estimates of the reported amount and assumptions about probability of occurrence of events far into the future. Examples include assumptions about future employment mortality and future salary increases. Amounts determined regarding the net pension liability are subject to continual revision as actual results are compared with past expectations and new estimates are made about the future.

Significant actuarial assumptions and other inputs used to measure the total pension liability:

- Measurement Date	June 30, 2015
- Valuation Date	June 30, 2014
- Expected Return on Investments	7.50%
- Inflation	2.75%
- Future Salary Increases	3.50%
- Mortality Assumption	RP 2000 Mortality Table set back projected at SCALE AA from year 2000. RP-2000 Males multiplied by 100%. RP-2000 Females multiplied by 90%.

Discount Rate - The discount rate used to measure the total pension liability was 7.50 percent. The projection of cash flows used to determine the discount rate assumed that contributions from participating employers in SCRS will be made based on the actuarially determined rates based on provisions in the South Carolina State Code of Laws. Based on those assumptions, the fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Long-term Expected Rate of Return - The long-term expected rate of return on pension plan investments for actuarial purposes is based upon the 30-year capital market outlook at the end of the third quarter 2012. The actuarial long-term expected rates of return represent best estimates of arithmetic real rates of return for each major asset class and were developed in coordination with the investment consultant for the Retirement System Investment Commission (RSIC) using a building block approach, reflecting observable inflation and interest rate information available in the fixed income markets as well as Consensus Economic forecasts. The actuarial long-term assumptions for other asset classes are based on historical results, current market characteristics, and professional judgment.

The RSIC has exclusive authority to invest and manage the retirement trust funds' assets. As co-fiduciary of the Systems, statutory provisions and governance policies allow the RSIC to operate in a manner consistent with a long-term investment time horizon. The expected real rates of investment return, along with the expected inflation rate, form the basis for the target asset allocation adopted annually by the RSIC. For actuarial purposes, the long-term expected rate of return is calculated by weighting the expected future real rates of return by the target allocation percentage and then adding the actuarial expected inflation which is summarized in the table below. For actuarial purposes, the 7.50 percent assumed annual investment rate of return used in the calculation of the total pension liability includes a 4.75 percent real rate of return and a 2.75 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long Term Expected Portfolio Real Rate of Return
Short Term			
Cash	2.0%	0.3	0.01
Short Duration	3.0%	0.6	0.02
Domestic Fixed Income			
Core Fixed Income	7.0%	1.1	0.08
High Yield	2.0%	3.5	0.07
Bank Loans	4.0%	2.8	0.11
Global Fixed Income			
Global Fixed Income	3.0%	0.8	0.02
Emerging Markets Debt	6.0%	4.1	0.25
Global Public Equity	31.0%	7.8	2.42
Global Tactical Asset Allocation	10.0%	5.1	0.51
Alternatives			
Hedge Funds (Low Beta)	8.0%	4.0	0.32
Private Debt	7.0%	10.2	0.71
Private Equity	9.0%	10.2	0.92
Real Estate (Broad Market)	5.0%	5.9	0.29
Commodities	3.0%	5.1	0.15
Total Expected Real Return	100.0%		5.88
Inflation for Actuarial Purposes			2.75
Total Expected Nominal Return			8.63

Sensitivity Analysis – The following table presents the Authority's collective net pension liability calculated using the discount rate of 7.50%, as well as what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower (6.50%) or 1.00% higher (8.50%) than the current rate.

	1.00% Decrease (6.50%)	Current Discount Rate (7.50%)	1.00% Increase (8.50%)
		(Thousands)	
Authority's proportionate share of the net pension liability	\$ 359,237	\$ 286,300	\$ 225,128

Other Retirement Benefits – The Authority also provides retirement benefits to certain employees designated by management and the Board under SERP. Benefits are established and may be amended by management and the Authority's Board and include retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, these plans were segregated into internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2006 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. At December 31, 2015, the Authority reported a liability associated with the three plans of \$12.7 million.

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	\$ 621	\$ 9
Changes of assumptions	0	0
Net difference between projected and actual earnings on pension plan investments	729	0
Authority's contributions subsequent to the measurement date	96	0
Total	\$ 1,446	\$ 9

The Authority reported \$96,000 as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2016. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years.

The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2015.

Year Ending June 30:	
	(Thousands)
2016	\$ 323
2017	323
2018	323
2019	323
2020	49
Total	\$ 1,341

Summer Nuclear Retirement – The Authority and SCE&G are parties to a joint ownership agreement at the Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel. Any earnings generated from the established pension plan are shared proportionately and used to reduce the allocated funding.

As of December 31, 2015, the Authority had a noncurrent pension liability balance of \$769,000. At December 31, 2014, the Authority had over-funded its share of requirements by \$766,000, which was applied to 2015.

In accordance with FASB ASC 715, the Authority has a regulatory liability balance of approximately \$19.6 million and \$18.6 million for the unfunded portion of pension benefits at December 31, 2015 and 2014, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2015.

NOTE 12 – OTHER POSTEMPLOYMENT BENEFITS (OPEB)

Vacation / Sick Leave – Full-time employees earn 10 days of vacation leave for service under five years and 15 days of vacation leave for service under 11 years. Employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn two hours per pay period, plus 20 additional hours at year-end for sick leave.

Employees may accumulate up to 45 days of vacation leave and 180 days of sick leave. Upon termination, the Authority pays employees for unused vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their sick leave at the pay rate then in effect.

Plan Description - The Authority participates in an agent multiple-employer defined benefit healthcare plan whereby PEBA Insurance Benefits provides certain health, dental and life insurance benefits for eligible retired employees of the Authority. The retirement insurance benefits available are defined by PEBA Insurance Benefits and substantially all of the Authority's employees may become eligible for these benefits if they meet retirement eligibility with a minimum of 10 years of earned service or upon reaching age 60 after leaving employment with at least 20 years of service. Currently, approximately 821 retirees meet these requirements.

For employees hired May 2, 2008 or thereafter, the number of years of earned service necessary to qualify for funded retiree insurance is 15 years for a one-half contribution, and 25 years for a full contribution. PEBA Insurance Benefits may be contacted at: PO Box 11661, Columbia, S.C. 29211-1661 and PEBA Retirement Benefits may be contacted at PO Box 11660, Columbia, S.C. 29211-1960.

Funding Policy - Prior to 2010, the Authority used the unfunded pay-as-you-go option (or cash disbursement) method pursuant to GASB 45 to record the net OPEB obligations. During 2010, the Authority elected to adopt an advanced or pre-funding policy and established an irrevocable trust with Synovus Trust Company. This method of funding will eventually result in lower contributions over time compared to the prior pay-as-you-go funding policy.

Annual OPEB Cost - The Authority's annual OPEB cost is calculated based on the annual required contribution (ARC) of the employer, an amount actuarially determined in accordance with the parameters of GASB 45. The ARC represents a level of funding that is projected (if paid on an on-going basis) to recognize the normal cost each year and to amortize any unfunded actuarial liabilities (or funding excess) over a period not to exceed 30 years. The Authority's contribution towards ARC is equal to the actual disbursements during the year for health care benefits for retired employees plus annual funding amounts for the trust. The Authority's annual OPEB cost (expense) was as follows:

Year Ended December 31,	2015	2014
	(Thousands)	
Annual required contribution	\$ 11,561	\$ 12,038
Interest on OPEB obligation	485	538
Adjustment to ARC	(440)	(464)
Annual OPEB cost	11,606	12,112
Net estimated employer contributions	(10,639)	(11,691)
Increase in net OPEB obligation	\$ 967	\$ 421
Net OPEB obligation-beginning of year	\$ 10,202	\$ 9,781
Net OPEB obligation-end of year	\$ 11,169	\$ 10,202

The Authority's annual OPEB cost, the percentage of annual OPEB cost contributed to the plan, and the net OPEB obligation for the year ended December 31, 2015 and the preceding two years were as follows:

Years Ended December 31,	Annual OPEB Cost	Employer Amount Contributed	Net OPEB Obligation	Percentage Contributed
		(Thousands)		(%)
2013	\$ 11,758	\$ 11,302	\$ 9,781	96.1
2014	12,112	11,691	10,202	96.5
2015	11,606	10,639	11,169	91.7

Funded Status and Funding Progress - The funded status of the Authority's retiree health care plan under GASB 45 as of December 31, 2014, the latest actuarial study date, is as follows:

Required Supplementary Information - Schedule of Funding Progress					
Actuarial Value of Assets (a)	Actuarial Accrued Liability (AAL) (b)	Annual Covered Payroll (c)	Unfunded AAL (UAAL) (b) - (a)	Funded Ratio (a / b)	Ratios of UAAL to Annual Covered Payroll (b-a)/(c)
(Thousands)					
					(%)
\$ 39,364	\$ 184,355	\$ 120,204	\$ 144,991	21.4	120.6

Note: As of December 31, 2015, the OPEB trust had assets of \$44.8 million.

The required schedule of funding progress presented as required supplementary information provided multi-year trend information that shows whether the actuarial value of plan assets is increasing over time relative to the actuarial accrued liability for benefits.

Actuarial Methods and Assumptions - The Projected Unit Credit actuarial cost method is used to calculate the ARC for the Authority's retiree health care plan. Using the plan benefits, the present health premiums and a set of actuarial assumptions, the anticipated future payments are projected. The projected unit credit method then provides for a systematic recognition of the cost of these anticipated payments. The yearly ARC is computed to cover the cost of benefits being earned by covered members, as well as to amortize a portion of the unfunded accrued liability.

Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events in the future. Amounts determined regarding the funded status and the annual required contributions of the Authority's retiree health care plan are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future.

Projections of health benefits are based on the plan as understood by the Authority and include the types of benefits in force at the valuation date and the pattern of sharing benefit costs between the Authority and its employees to that point. Actuarial calculations reflect a long-term perspective and employ methods and assumptions that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets. Significant methods and assumptions were as follows:

Actuarial Methods and Assumptions	
Inflation rate	3.00% per annum
Investment rate of return	4.75% net of expenses
Actuarial cost method	Projected Unit Credit Cost Method
Amortization method	Level as a percentage of employee payroll
Amortization period	30 year, open amortization
Payroll growth	3.00% per annum
Medical trend:	
Initial	6.00%
Ultimate	4.50% after 9 years
Drug trend:	
Initial	6.00%
Ultimate	4.50% after 9 years

Summer Nuclear OPEB - The Authority is responsible for funding its share of OPEB costs for nuclear station employees. The Authority's liability balances as of December 31, 2015 and 2014 were approximately \$11.1 million and \$10.5 million, respectively.

In accordance with FASB ASC 715, the Authority recorded a regulatory liability of approximately \$3.2 million and \$4.6 million for the unfunded portion of OPEB costs at December 31, 2015 and 2014, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2015.

NOTE 13 – CREDIT RISK AND MAJOR CUSTOMERS

In 2015, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:	2015	2014
	(Millions)	
Central	\$ 1,070	\$ 1,118

The Authority maintains an allowance for uncollectible accounts based upon the expected collectability of all accounts receivable. The allowance at each year ended December 31, 2015 and 2014 was \$1.7 million and \$1.6 million, respectively.

NOTE 14 – STORM DAMAGE

2015

In October 2015, the Authority's system sustained damages from flooding associated with an unusual rainfall event in South Carolina. As a result, several counties in South Carolina were designated as federal disaster areas. The damage sustained by the Authority in these counties had impacts on the Authority's generation, transmission and distribution systems. At December 31, 2015, the Authority recorded a receivable of \$3.6 million for federal reimbursement of associated damages. Additional costs will be incurred in 2016 that may also qualify for federal reimbursement.

2014

In February 2014, the Authority's system sustained damages from Winter Storm Pax (Pax). As a result, several counties in South Carolina were designated as a federal disaster area. The damage sustained by the Authority in these counties was mainly to the Authority's transmission and distribution systems.

As of December 31, 2014, all the restoration and repair work had been completed and/or accrued to capital cost or maintenance expense. The Authority received disaster relief assistance from federal sources on all eligible costs from the storm as of the close of 2014. The damages to the distribution system resulted in capital restoration costs of \$1.9 million and federal reimbursement of \$1.3 million. Damages to the transmission system resulted in maintenance expense and capital costs of approximately \$761,000 and \$632,000, respectively. The Authority received federal reimbursement of approximately \$832,000.

The Authority does not expect to increase rates due to the impact of Pax and foresees no measurable long-term impact on its operations or the demand for electricity by its customers.

NOTE 15 – CHANGE IN ACCOUNTING PRINCIPLE/RESTATEMENT

The Authority implemented GASB statement 68, Accounting and Financial Reporting for Pensions (an amendment of GASB Statement No. 27) as amended by statement 71, Pension Transition for Contributions Made Subsequent to the Measurement Date, in the year ended December 31, 2015. The implementation of the statement required the Authority to record a beginning net pension liability and the effects on net position of contributions made by the Authority during the measurement period (year ended December 31, 2014). As a result, net position as of January 1, 2015 decreased by \$261.1 million.

NOTE 16 – SUBSEQUENT EVENTS

On February 10, 2016, the Authority issued \$543.7 million of Revenue Obligations, 2016 Tax-exempt Refunding Series A Bonds. The bond proceeds were used to refund a portion of the following Revenue Obligations: 2007 Tax-exempt Series A, 2008 Tax-exempt Series A, 2009 Tax-exempt Refunding Series A, 2009 Tax-exempt Series B and 2014 Tax-exempt Series A. This issue resulted in a gross savings of \$122.4 million over the life of the bonds.

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BOARD OF DIRECTORS



W. Leighton Lord III

*Chairman
Columbia, S.C.*

Director Lord is a partner in Nexsen Pruet law firm in Columbia.



William A. Finn

*1st Vice Chairman
1st Congressional District
Mount Pleasant, S.C.*

Director Finn is chairman of AstenJohnson Inc., a specialty textile company for the printing and papermaking industries based in Charleston.



Barry D. Wynn

*2nd Vice Chairman
4th Congressional District
Spartanburg, S.C.*

Director Wynn is president of Colonial Trust Company, a private trust company specializing in investment management and estate services.



Kristofer D. Clark
3rd Congressional District
Easley, S.C.

Director Clark is a broker with Easlan Capital and owner of Pristine Properties LLC.



Merrell W. Floyd
7th Congressional District
Conway, S.C.

Director Floyd retired in 2005 as staff coordinator at Horry Electric Cooperative.



J. Calhoun Land IV
6th Congressional District
Manning, S.C.

Director Land is a partner in Land, Parker & Welch, a general practice firm in Manning.



Peggy H. Pinnell

*Berkeley County
Moncks Corner, S.C.*

Director Pinnell is the owner of the Peggy H. Pinnell Insurance Agency in Moncks Corner, a State Farm agency.



Dan J. Ray

*Georgetown County
Georgetown, S.C.*

Director Ray is a managing director and the global head of project finance for Jefferies LLC.



Alfred L. Reid Jr.

*5th Congressional District
Rock Hill, S.C.*

Director Reid is the production manager of Boral Stone Products in Chester.



David F. Singleton

*Horry County
Myrtle Beach, S.C.*

Director Singleton is president of Singleton Properties, a real estate investment and sales firm.



Jack F. Wolfe Jr.

*2nd Congressional District
Chapin, S.C.*

Director Wolfe is a past president and CEO of Mid-Carolina Electric Cooperative in Lexington, S.C.

Notes:

The South Carolina Senate on June 4, 2015, confirmed Director Alfred L. Reid Jr. to the Santee Cooper Board of Directors and reappointed directors Ray, Wolfe and Wynn.

Director Catherine E. Heigel resigned her at-large seat on June 4, 2015, to become director of the South Carolina Department of Health and Environmental Control.

ADVISORY BOARD

Nikki R. Haley	<i>Governor</i>
Alan Wilson	<i>Attorney General</i>
Mark Hammond	<i>Secretary of State</i>
Richard Eckstrom	<i>Comptroller General</i>
Curtis M. Loftis Jr.	<i>State Treasurer</i>

EXECUTIVE LEADERSHIP

Lonnie N. Carter	<i>President and Chief Executive Officer</i>
Jeffrey D. Armfield	<i>Senior Vice President and Chief Financial Officer</i>
J. Michael Baxley	<i>Senior Vice President and General Counsel</i>
Michael R. Crosby	<i>Senior Vice President, Nuclear Energy</i>
Arnold R. Singleton¹	<i>Senior Vice President, Power Delivery</i>
Marc R. Tye²	<i>Executive Vice President, Competitive Markets & Generation</i>
Pamela J. Williams	<i>Senior Vice President, Corporate Services</i>

MANAGEMENT

S. Thomas Abrams	<i>Vice President, Planning and Power Supply</i>
Charles S. “Sam” Bennett³	<i>Vice President, Administration</i>
Michael C. Brown	<i>Vice President, Wholesale and Industrial Services</i>
Thomas B. Curtis⁴	<i>Vice President, Generating Stations</i>
Glenda W. Gillette	<i>Vice President and Controller</i>
Jane H. Hood	<i>Vice President, Fuels Strategy and Supply</i>
Thomas L. Kierspe	<i>Vice President, Environmental, Property and Water Systems Management</i>
Richard S. Kizer	<i>Vice President, Public Affairs</i>
J. Michael Poston	<i>Vice President, Retail Operations</i>
Suzanne H. Ritter	<i>Treasurer and Vice President, Corporate Planning</i>
Laura G. Varn	<i>Vice President, Human Resource Management</i>
Elizabeth H. Warner	<i>Vice President, Legal Services and Corporate Secretary</i>

AUDITOR

Kenneth W. Lott III	<i>General Auditor</i>
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1. Arnold R. Singleton was named Senior Vice President, Power Delivery effective Dec. 8, 2015.
2. Marc R. Tye was named Executive Vice President, Competitive Markets & Generation effective Aug. 24, 2015.
3. Charles S. “Sam” Bennett was named Vice President, Administration effective Dec. 8, 2015.
4. Thomas B. Curtis was named Vice President, Generating Stations effective Dec. 8, 2015.

OFFICE LOCATIONS

CONWAY OFFICE

100 Elm Street
Conway, SC 29526
843-248-5755
843-248-7315 – fax

LORIS OFFICE

3701 Walnut Street
Loris, SC 29569
843-756-5541
843-756-7008 – fax

MONCKS CORNER OFFICE

Santee Cooper Headquarters
One Riverwood Drive
Moncks Corner, SC 29461
843-761-8000
843-761-4122 – fax

MURRELLS INLET/ GARDEN CITY OFFICE

900 Inlet Square Drive
Murrells Inlet, SC 29576
843-651-1598
843-651-7889 – fax

MYRTLE BEACH OFFICE

1703 Oak Street
Myrtle Beach, SC 29577
843-448-2411
843-626-1923 – fax

NORTH MYRTLE BEACH OFFICE

1000 2nd Avenue North
North Myrtle Beach, SC 29582
843-249-3505
843-249-6843 – fax

PAWLEYS ISLAND OFFICE

126 Tiller Road
Pawleys Island, SC 29585
843-237-9222
843-237-8959 – fax

Notes:

Santee Cooper closed the Carolina Forest and St. Stephen offices effective Dec. 31, 2015. The Loris and Pawleys Island offices are scheduled to close June 30, 2016.