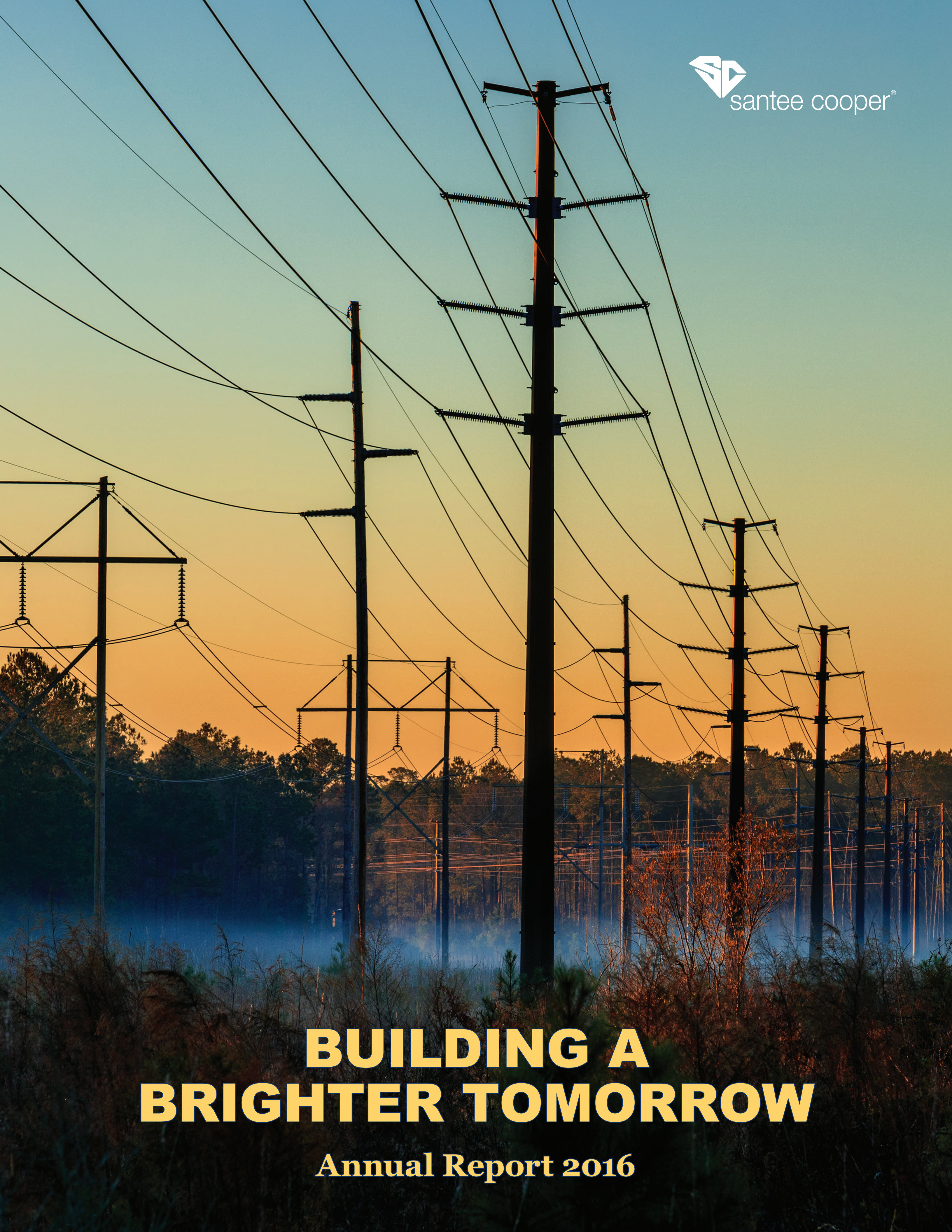

santee cooper®

BUILDING A BRIGHTER TOMORROW

Annual Report 2016

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Chairman and CEO Letter

As dawn broke on Oct. 8, we waited for Hurricane Matthew. Passing along the South Carolina coast before making landfall in McClellanville as a Category 1 storm, Matthew caused widespread damage, impacting 33 percent of our transmission system and leaving 137,000 retail customers without power. It was the biggest challenge our customers and Santee Cooper employees faced in 2016.

It was a challenge they accepted and overcame. Each day, employees built on the foundations of the day before until power was restored to all customers who could receive it. It was hard work with long hours and challenging conditions. However, we were bolstered by our customers' support and knew we were building a brighter tomorrow for them.

Other noteworthy challenges and successes in 2016 made way for the future. We continue to be proud Santee Cooper's power costs are significantly below the national average and that our reliability remains solid. In 2016, transmission reliability was 99.9976 percent, distribution reliability was 99.9955 percent and the generation availability factor was 90.18 percent.

We reclaimed 621,678 tons of ash for beneficial use from ash ponds at Winyah, Jefferies and Grainger generating stations. The demolition of Grainger Generating Station marked the end of an era when its two 300-foot stacks tumbled to the ground on Feb. 6. The coal-fired station was retired as part of the utility's move to a more diverse mix of generating resources, including additional renewable resources and nuclear generation.

To that end, Santee Cooper and nuclear partner South Carolina Electric & Gas Co. (SCE&G) reached assembly and contract milestones in the construction of units 2 and 3 at V.C. Summer Nuclear Station in 2016. Among other achievements, the first containment vessel ring for unit 3 was placed in April, the reactor vessel for unit 2 was placed in August and the 2.4 million pound module for unit 3 was placed in December.

In June, the Board of Directors authorized executives to proceed with securing an option that substantially fixes the costs to complete the two units at V.C. Summer. The fixed price option is an additional benefit to an amended Engineering, Procurement and Construction (EPC) Agreement that gives greater cost and schedule certainty to customers.

Nuclear power is virtually emissions-free. These new units are critical as Santee Cooper continues to move to a more diverse mix of generating resources and an uncertain regulatory future. They're also critical to our 2009 goal of meeting 40 percent of our customers' energy needs by 2020 with non-greenhouse emitting resources, renewable resources, conservation and energy efficiency.

Regarding the new nuclear units, Toshiba announced new financial issues in February 2017 (see Note 7 and 16 to these financial statements). We remain in close contact with Toshiba and its subsidiary Westinghouse on the progress of the new units and on Toshiba's financial situation. The contractor remains committed to the project, as do Santee Cooper and partner SCE&G. We are working diligently on the completion of Units 2 and 3.

Our Reduce The Use rebate programs are another way we work toward that 2020 target. Santee Cooper's Reduce The Use 2016 energy savings goal was 18.3 gigawatt hours (GWh). We exceeded that goal by achieving 28.1 GWh of energy savings through commercial and residential Reduce The Use programs.

We also had great success with the spring Mini-Bond sale, which took place in April. It was the largest, most successful Mini-Bond sale in Santee Cooper history, totaling $42,142,700 from 2,297 separate purchases. Santee Cooper Mini-Bonds give investors an easy and unique way to enhance their portfolios. Mini-Bonds also help Santee Cooper fulfill our responsibility to provide South Carolina with low-cost, reliable and environmentally protective electricity.

Bond rating agencies and large investors continue to regard Santee Cooper favorably. We had successful bond sales in 2016 totaling $1.5 billion, $100 million of that in economic refunding bonds, which produced a savings of approximately $89 million over the life of the bonds.

Central and the electric cooperatives of South Carolina are important customers, and we'll continue to work on their behalf in 2017. We will also continue to emphasize the importance of customer service in our retail operations. In 2016, we added more convenient ways for our retail customers to do business with us. We partnered with Western Union to provide 1,300 new locations in South Carolina alone for customers to pay their bills. Additionally, we focused our resources on our busiest retail offices, closing two that were used with less frequency.

Customers have had an increased interest in solar power, and we're working to make solar easy and affordable for them. On March 21, our Board of Directors approved the state's first community solar project and new rebate-focused solar programs. The timing couldn't have been better, coming 10 years after Santee Cooper introduced solar to the South Carolina grid. We will be reviewing the rebates and subscription prices for our solar programs each year to help encourage the use of this renewable energy source.

Solar and other sources of renewable energy are complex, offering both advantages and challenges. To help our schoolchildren get hands-on experience with solar power, we partnered with the electric cooperatives and our municipal customers in 2006 to bring solar arrays to middle schools across the state. The Bamberg Department of Public Works and Santee Cooper dedicated its 28th Solar School at Richard Carroll Elementary School in April.

Santee Cooper continued to promote prominent Green Power events in 2016. We teamed up with Palmetto Electric Cooperative to power the RBC Heritage with Green Power for the 8th year in a row. We also joined Pee Dee Electric Cooperative to fuel Darlington Raceway's Bojangles' Southern 500 weekend with Green Power. Both were great ways to celebrate the 15th anniversary of placing Green Power on the grid.

For years, Santee Cooper has also worked jointly with the electric cooperatives on economic development initiatives. We offer tools including loans, grants and attractive incentive rates. Those programs assist with items like infrastructure and construction of speculative buildings in Santee Cooper, cooperative and municipal customers' territories. Collectively, efforts in 2016 allowed Santee Cooper and electric cooperatives power system to add 43 location announcements, $830.6 million in capital investment and 5,006 new jobs. We will continue to work with the electric cooperatives in the future to build brighter tomorrows for all South Carolinians.

Protection of physical and cyber assets has become another major focus for Santee Cooper. Hackers have targeted U.S. industry for years and each attempt gets more sophisticated. Electric utilities are primary targets – both our physical and digital assets – and Santee Cooper will continue working with peer utilities and security experts to keep abreast of new threats and develop new tools to protect our assets.

Overall, we believe our employees are the reason for our successes. Santee Cooper has one of the best groups of employees in the industry. We have good training programs in place, and we have created educational partnerships externally to keep our talent pipeline full and prepare for anticipated retirements. Santee Cooper remains committed to developing our employees, both for their own advancement and so that we can continue to build brighter tomorrows by serving South Carolina with affordable and reliable electricity, environmental stewardship, economic development, and excellent customer service.

W. Leighton Lord III
Chairman

Lonnie N. Carter
President and CEO

Corporate Statistics

System Data 2016

Miles of transmission system lines: **5,056**

Miles of distribution system lines: **2,862**

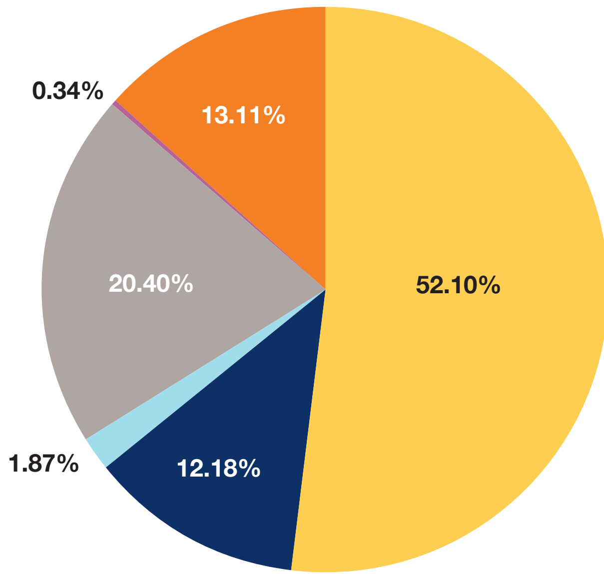
Number of transmission substations: **106**

Number of distribution substations: **54**

Number of CEPCI Delivery Points (DPs): **458**

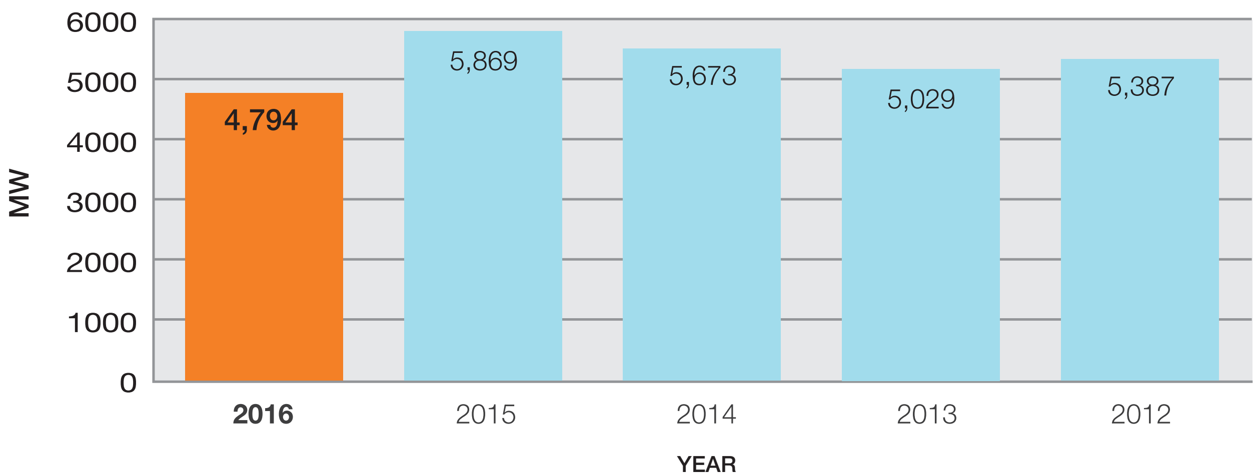
	2016	2015	2014	2013	2012
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,718,565**	$1,842,541	$2,023,414	$1,823,502	$1,897,135
Total Expenses & Interest Charges	**1,604,119**	1,781,591	1,894,217	1,744,960	1,801,813
Other	**(6,708)**	(6,435)	19,798	7,396	9,155
Reinvested Earnings	**107,738**	54,515	148,995	85,938	104,477
OTHER FINANCIAL					
(Excluding CP and Other)					
Debt Service Coverage *(prior to Distribution to State)*	**1.55**	1.45	1.53	1.52	1.44
Debt / Equity Ratio	**79/21**	78/22	75/25	75/25	73/27
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**176,748**	174,023	171,567	168,813	166,809
Military and Large Industrial	**27**	27	28	29	29
Wholesale	**4**	4	4	4	4
Total Customers	**176,779**	174,054	171,599	168,846	166,842
Generation (GWh):					
Coal	**12,347**	12,832	16,607	13,949	15,888
Nuclear	**2,886**	2,366	2,297	2,788	2,421
Hydro	**444**	523	506	624	271
Natural Gas and Oil	**4,834**	6,212	3,821	4,315	4,710
Landfill Gas and Renewables	**81**	93	96	115	103
Total Generation (GWh)	**20,592**	22,026	23,327	21,791	23,393
Purchases, Net Interchanges, etc. (GWh)	**3,433**	4,987	4,738	5,335	4,099
Wheeling, Interdepartmental, and Losses	(325)	(515)	(712)	(762)	(736)
Total Energy Sales (GWh)	**23,700**	26,498	27,353	26,364	26,756
Summer Maximum Continuous Rating (MCR) Generating Capability (MW)	**5,104**	5,093	5,182	5,183	5,665
Territorial Peak Demand (MW)	**4,794**	5,869	5,673	5,029	5,387

2016 GENERATION BY FUEL MIX

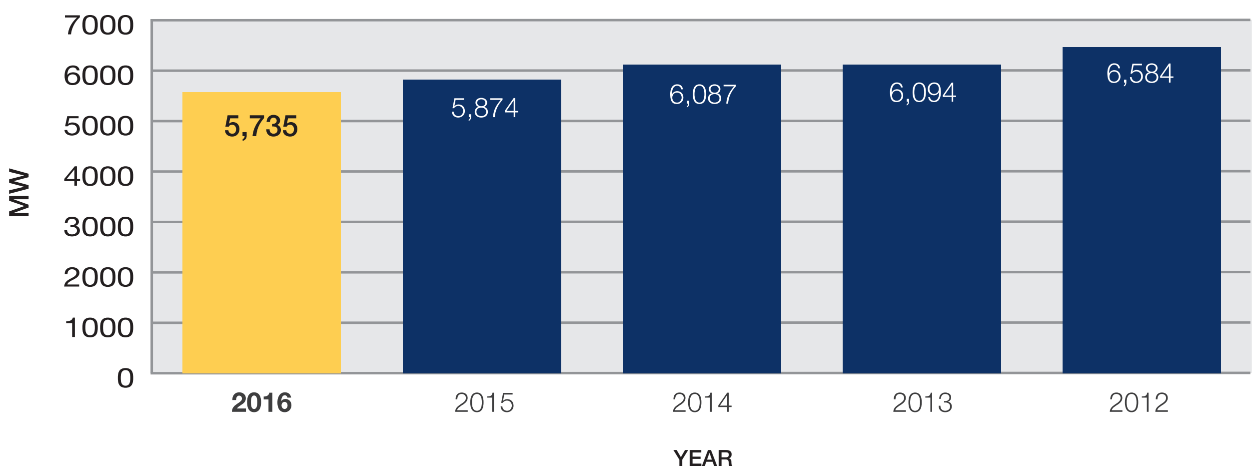


Source		GWh
Coal	52.10%	12,347
Nuclear	12.18%	2,886
Hydro	1.87%	444
Natural Gas & Oil	20.40%	4,834
Other Renewables	0.34%	81
Purchases (Net)	13.11%	3,108
	100.00%	23,700

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, Jack F. Wolfe Jr., Alfred L. Reid Jr. and Stephen H. Mudge.

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.

Peggy H. Pinnell

Peggy H. Pinnell
Chairwoman
2016 Audit Committee

Notes:
Director Stephen H. Mudge was appointed to the Board on June 2, 2016, 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 5,104 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, 322 MW of nuclear capacity, 136 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 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.

In order to further diversify its fuel mix, the Authority has an ownership interest with South Carolina Electric & Gas (SCE&G) in two 1,117 MW, nuclear generating units under construction at Summer Nuclear (Units 2 and 3).

Questions concerning any of the information provided in this report or requests for additional information should be addressed to Suzanne H. Ritter, 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 and 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, 2016, 2015 and 2014 are summarized below:

	2016	2015	2014
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 8,214,787**	$ 7,509,121	$ 6,917,786
Current assets	**2,779,166**	3,155,271	2,837,902
Other noncurrent assets	**1,244,276**	1,329,395	1,248,905
Deferred outflows of resources	**271,595**	256,734	203,638
Total assets & deferred outflows of resources	**$ 12,509,824**	$ 12,250,521	$ 11,208,231
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 8,134,916**	$ 7,306,469	$ 6,639,162
Current liabilities	**916,567**	1,299,591	1,031,382
Other noncurrent liabilities	**1,185,935**	1,469,189	1,160,723
Deferred inflows of resources	**242,070**	233,482	208,501
Total liabilities & deferred inflows of resources	**$ 10,479,488**	$ 10,308,731	$ 9,039,768
NET POSITION			
Net invested in capital assets	**$ 1,168,907**	$ 1,195,402	$ 957,835
Restricted for debt service	**39,158**	79,771	108,457
Restricted for capital projects	**1,663**	4,304	6,515
Unrestricted	**820,608**	662,313	1,095,656
Total net position	**$ 2,030,336**	$ 1,941,790	$ 2,168,463
Total liabilities, deferred inflows of resources & net position	**$ 12,509,824**	$ 12,250,521	$ 11,208,231

2016 Compared to 2015

The primary changes in the Authority's combined financial condition as of December 31, 2016 and 2015 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $259.3 million during 2016 due to increases of $705.7 million in capital assets and $14.8 million in deferred outflows of resources. These increases were offset by decreases of $376.1 million in current assets and $85.1 million in other noncurrent assets.

The increase in capital assets of $705.7 million was due to net construction work in progress increases of $955.6 million partially offset by a net decrease in utility plant and other physical property of $249.9 million. The increase resulted primarily from additions associated with Summer Nuclear Units 2 and 3, which are not currently in service.

The decrease in current assets of $376.1 million was due to a net decrease of $282.3 million in unrestricted and restricted cash, cash equivalents and investments resulting from the 2016 bond activity impact, construction payments and debt service payments. Fossil fuel inventory decreased $88.4 million due to lower coal purchases during 2016. Prepaid expenses and other current assets decreased $36.4 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. The remaining $31.0 million was an increase resulting from the net change in receivables, materials inventory, nuclear fuel and interest receivable.

The decrease in other noncurrent assets of $85.1 million resulted from a reduction of $61.3 million in deferred interest related to the sale of five percent of the Summer Nuclear Units 2 and 3 being transferred to construction work in progress as capitalized interest. Further decreases of $27.7 million were provided by the asset retirement obligation due to accretion and depreciation on nuclear and ash pond assets. Other items with a net increase of $3.9 million are due to the residual changes in the other accounts in this category.

The increase in deferred outflows of resources of $14.8 million was largely due to the increase of $46.4 million in unamortized loss on refunded and defeased debt, which resulted from the 2016 bond activity. Pension related deferred outflows increased $20.2 million from the Authority reporting its share of pension deferrals. The net impact of accumulated decrease in fair value of hedging derivatives was a reduction of $51.8 million from decreased mark-to-market losses driven by higher natural gas prices during 2016.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $170.8 million due to increases of $828.4 million in long-term debt-net and $8.6 million in deferred inflows of resources. These increases were partially offset by decreases of $383.0 million in current liabilities and $283.2 million in other noncurrent liabilities.

Net long-term debt increased $828.4 million due mainly to net additions of $700.1 million in total long-term debt and $128.3 million in unamortized debt discounts and premiums. The increase in long-term debt was mainly due to additions of $1.6 billion from the 2016 bond activity. Offsetting this were decreases of $120.9 million for transfers to current portion of long-term debt and $751.5 million for defeasance and/or refunding activity. Unamortized debt discounts and premiums increased due to net additions of $173.2 million from the 2016 bond activity offset by decreases of $38.0 million for amortization of discounts and premiums and $6.9 million in removals from refunding activity.

The decrease in current liabilities of $383.0 million was due to decreases of $197.6 million in commercial paper and $129.1 million in accounts payable. Additional changes were caused by decreases in the current portion of long-term debt of $38.8 million and a $13.0 million reduction in accrued interest on long-term debt. Further reductions of $4.5 million were due to the residual changes in the other accounts in this category.

Other noncurrent liabilities decreased $283.3 million primarily from an adjustment to the asset retirement obligation of $306.2 million resulting from the 2016 TLG Service, Inc. decommissioning study generating a lower liability for nuclear decommissioning costs. Further decreases were due to lower gas hedging transactions of $24.5 million. Partially offsetting these decreases were higher pension and Other Post-Employment Benefits (OPEB) liabilities of $42.8 million. Net increases of $4.6 million among the remaining accounts make up the residual variance.

Deferred inflows of resources increased $8.6 million due to increases of $7.1 million in nuclear decommissioning costs from market value adjustments, amortization and interest accruals for decommissioning funds and $5.3 million from accumulated increase in fair value of hedging derivatives. Partially offsetting these increases were pension related deferred inflow decreases of $3.8 million associated with the Authority's share of pension deferrals.

The increase in net position of $88.5 million was mainly due to an increase in unrestricted of $158.3 million. This increase was offset by a $26.5 million decrease related to net invested in capital assets due to a higher amount of unspent construction proceeds netted against a lower amount of construction work in progress and utility plant. Restricted for debt service decreased $40.7 million due to changes in accrued interest on long-term debt and reductions in bond and debt service funds. A $2.6 million reduction of non-borrowed funds for the Lake Moultrie Water Agency capacity upgrade caused a decrease in restricted for capital projects.

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 and 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.

Results of Operations

Santee Cooper's Combined Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2016, 2015 and 2014 are summarized as follows:

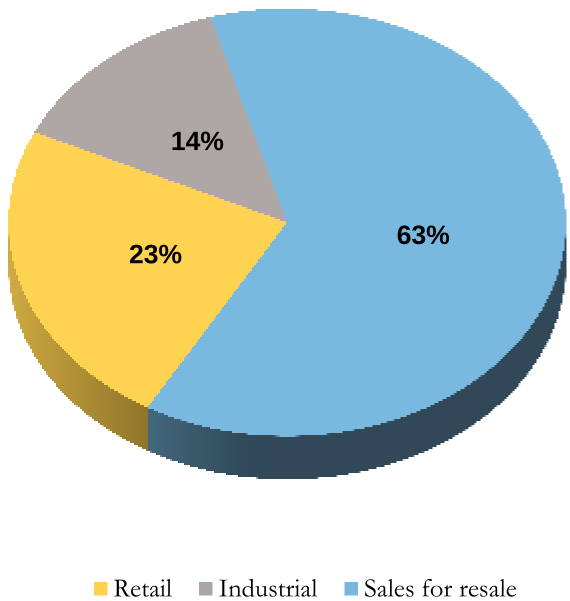
	2016	2015	2014
		(Thousands)	
Operating revenues	**$ 1,745,657**	$ 1,879,553	$ 1,997,347
Operating expenses	**1,374,942**	1,502,488	1,619,224
Operating income	**370,715**	377,065	378,123
Interest expense	**(229,177)**	(279,103)	(274,993)
Costs to be recovered from future revenue	**(6,708)**	(6,435)	19,798
Other income (expense)	**(27,092)**	(37,012)	26,067
Capital contributions & transfers	**(19,192)**	(20,116)	(20,659)
Change in net position	**$ 88,546**	$ 34,399	$ 128,336
Net position - beginning of period as previously reported	**1,941,790**	2,168,463	2,040,127
Restatement (Note 15)	**0**	(261,072)	0
Net position - beginning of period as restated	**1,941,790**	1,907,391	2,040,127
Ending net position	**$ 2,030,336**	$ 1,941,790	$ 2,168,463

2016 Compared to 2015

Operating Revenues

As compared to 2015, operating revenues decreased $133.9 million (7%). The drivers for this decrease were lower kWh sales (11%) and demand usage (14%) resulting from the combined reduced load from industrial and wholesale customers as well as impacts between the 2015 and 2016 Central COS adjustments. Lower fuel rate revenues also contributed to this decrease. Partially offsetting this decrease was higher demand, operation and maintenance (O&M) and energy related fixed cost rates. Energy sales for 2016 totaled approximately 23.7 million megawatt hours (MWhs) as compared to approximately 26.5 million MWhs for 2015.

2016 Revenues from Sales of Electricity*
by Customer Class

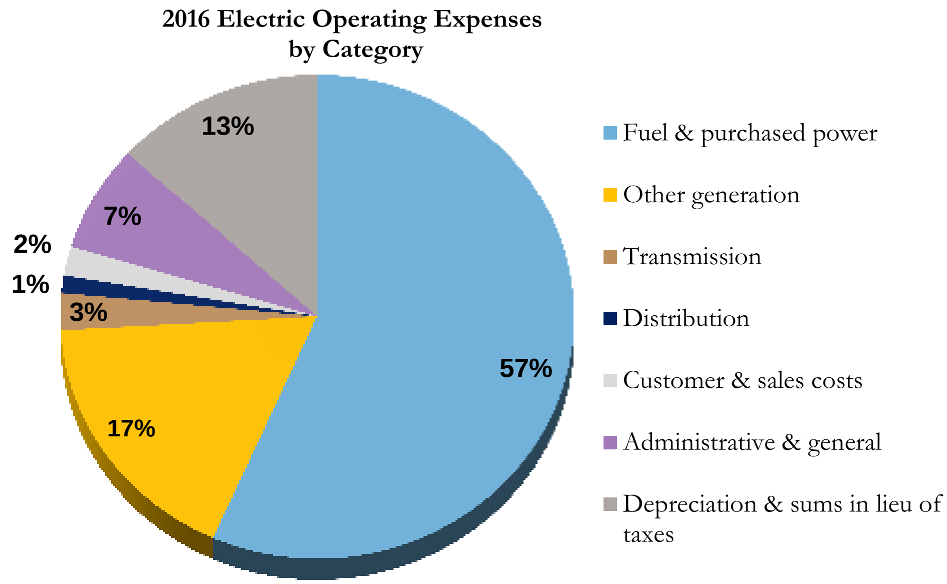


	2016	2015	2014
Revenues from Sales of Electricity*		(Thousands)	
Retail	**$ 406,246**	$ 381,049	$ 394,195
Industrial	**234,463**	354,148	399,817
Sales for resale	**1,080,399**	1,121,326	1,181,350
Totals	**$ 1,721,108**	$ 1,856,523	$ 1,975,362

*Excludes interdepartmental sales of $524 for 2016, $478 for 2015 and $488 for 2014.

Operating Expenses

Combined operating expenses for 2016 decreased $127.5 million (8%) as compared to 2015. The main driver was fuel and purchased power expense which decreased by $131.2 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 ($1.2 million) from labor and Summer Nuclear Unit 1 expenses as well as administrative & general ($4.8 million) from pension-related benefits, prepayment write-off, donations and sponsorships. Other smaller variances ($2.3 million) netted a decrease and were spread among the remaining cost categories.



		2016		2015		2014
Electric Operating Expenses				(Thousands)		
Fuel & purchased power	**$**	**775,737**	$	906,954	$	1,057,907
Other generation		**238,912**		237,680		210,083
Transmission		**33,767**		35,425		32,998
Distribution		**15,865**		15,340		14,503
Customer & sales costs		**26,636**		28,792		27,994
Administrative & general		**98,006**		93,171		92,967
Depreciation & sums in lieu of taxes		**180,725**		180,167		178,037
Totals	**$**	**1,369,648**	$	1,497,529	$	1,614,489

Net Below the Line Items

- Other income increased by $9.9 million due to higher interest income, increase in the fair value of investments and a decrease in the loss on sale of coal due to the remainder of the Jefferies Generating Station coal sale being finalized.

- Interest expense for 2016 was $49.9 million lower primarily due to an increase in capitalized interest associated with Summer Nuclear Units 2 and 3. This increase resulted from a plan to decrease the amount of interest expense paid from revenues during construction.

- Cost to be recovered (CTBR) changed $0.3 million.

- Capital contributions and transfers represent dollars paid to the state of South Carolina. This payment, which is based on a percentage of total budgeted revenues, decreased by $0.9 million due to lower revenues in the 2016 budget compared to the 2015 budget.

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.

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.

Net Below the Line Items

- Other income decreased by $63.1 million due to two one-time items that occurred in 2014, reclassification of the Duke Energy good faith deposit and higher interest income from the Santee River case settlement. In addition in 2015 the amortization of the remaining balance of assets from a cancelled coal-fired generation project in Florence County, S.C. began.

- 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 CTBR methodology, effective January 1, 2015.

- Capital contributions and transfers represent dollars paid to the state of South Carolina. This payment, which is based on a percentage of total budgeted revenues, decreased by $0.5 million due to lower revenues in the 2015 budget compared to the 2014 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 continues to be 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 use. Since June 2012, the Authority has invested over $60.0 million throughout South Carolina in product development through low-interest revolving loans to public entities. In addition, the Authority created two additional funds to further improve the readiness of industrial sites in Cooperative and municipal customers' territories, directly or indirectly served by Santee Cooper. Approvals through 2016 total more than $8.0 million from the municipal site readiness fund and over $11.0 million from the South Carolina Power Team Site Readiness Fund. The Authority also offers the Experimental Large Light and Power Economic Development Service Tiered Rider. The purpose of this rider is to attract new and expanding industrial loads and is available to the Authority's direct served industrial customers as well as industrial customers indirectly served through its wholesale customers located in South Carolina.

In May 2015, Swedish automaker Volvo announced that it will build its first U.S. factory in Berkeley County, S.C., spending up to $500.0 million on a plant with an initial capacity of 100,000 vehicles a year. Volvo's announcement stated the first vehicles should roll off the line in 2018. The Authority worked with the State, Berkeley County and the Electric Cooperatives to recruit Volvo to this site. The manufacturing site will be served by Edisto Electric Cooperative, one of the Central Cooperatives. The Authority owns approximately 3,900 acres adjacent to the Volvo site and is currently master planning the property as an industrial park to serve Volvo suppliers and other industries. The Volvo project, as well as the industrial park development, is proceeding as planned. The Authority expects this Central customer load to be approximately 100,000 MWh annually once the plant commences operation.

The Authority's largest customer, Central Electric Power Cooperative (Central), accounted for 59.1 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, allows Central to transition the purchase of the 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 and 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, in May 2013, the Authority and Central agreed to extend their rights to terminate as noted in the September 2009 Agreement until December 31, 2058 (Central Agreement). 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 2016, 2015 and 2014 was as follows:

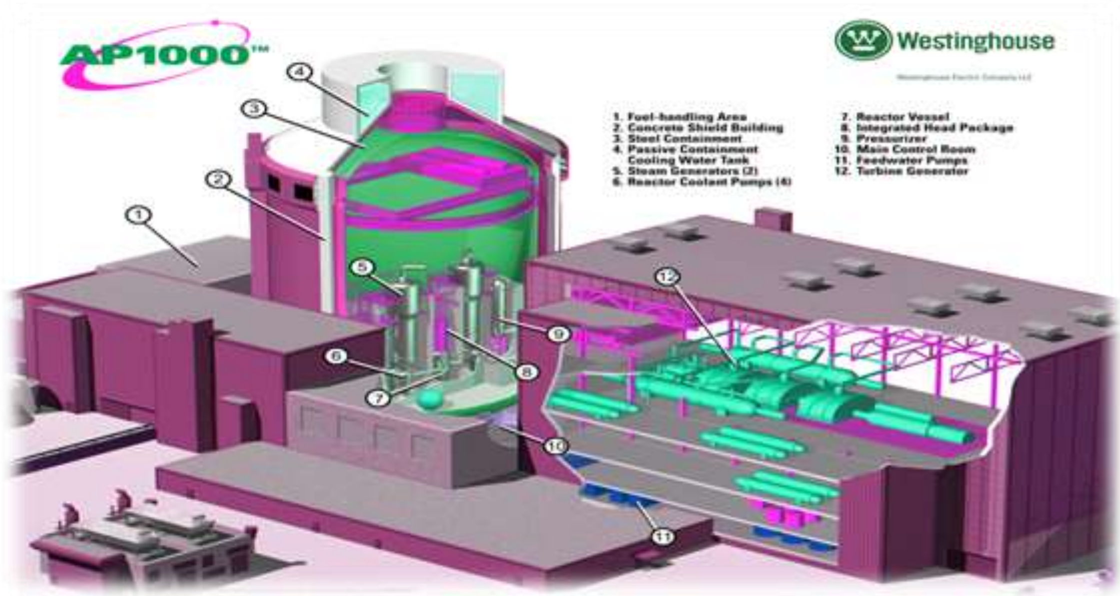
	2016	2015	2014
	Budget 2017-19	Budget 2016-18	Budget 2015-17
Capital Improvement Expenditures		(Thousands)	
Environmental compliance	**$ 582,922**	$ 318,972	$ 154,939
General improvements to the system	**1,048,474**	698,773	566,761
Summer Nuclear Units 2 and 3 (1)	**2,222,554**	1,693,252	1,677,228
Totals	**$ 3,853,950**	$ 2,710,997	$ 2,398,928

(1) Excludes capitalized interest.

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 Electric Company, LLC ("Westinghouse") AP 1000 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. The AP 1000 is the first and only reactor in its class of technological development, referred to as "Generation III+" to receive certification from the Nuclear Regulatory Commission ("NRC"). The AP 1000 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.



Nuclear Regulatory Commission Approvals. The NRC has approved the AP 1000 standard plant design for Summer Nuclear Units 2 and 3. In addition, the NRC has issued the Combined Construction and Operating Licenses ("COLs") with certain conditions for Summer Nuclear Units 2 and 3. To address these conditions, the Authority and SCE&G submitted an overall implementation plan. SCE&G and the Authority are implementing the plan and expect to complete all requirements prior to fuel load as required by the NRC. The Authority and SCE&G do not anticipate any additional regulatory actions related to the plan, but cannot predict future regulatory requirements and how they may impact construction or operation of the new units.

Ownership of the Summer Nuclear Units 2 and 3. On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement specifying an Authority ownership interest of 45% 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. The Authority and SCE&G also entered into an Operating and Decommissioning Agreement on October 20, 2011 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.

In December 2015, the Authority and SCE&G executed a Purchase and Sale Agreement (the "PSA") whereby SCE&G will purchase from the Authority an additional 5% interest in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Such sale is subject to regulatory approvals including approval of the Public Service Commission ("PSC") and the NRC. Under the terms of the agreement, SCE&G will own 60% of the two new nuclear units and the Authority will own 40%. The 5% ownership interest will be acquired in three stages, with 1% to be acquired at the commercial operation date of the first new nuclear unit, an additional 2% to be acquired no later than the first anniversary of such commercial operation date and the final 2% to be acquired no later than the second anniversary of such commercial operation date. The purchase price will be based on a pro-rata share of the Authority's actual cost of the units and reimbursement of its financing costs based on the percentage conveyed as of the date of the conveyance. The total purchase price is estimated to be between $700.0 and $900.0 million. The PSA does not impact the Authority's payment obligation for the full 45% ownership during construction. Under the terms of the PSA, the Authority cannot enter into an agreement to sell an additional portion of its 40% ownership interest until both units have been completed. However, under the PSA the Authority is free to explore power sale opportunities from the facility.

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 Agreement (the "EPC Agreement"), with a consortium consisting of Westinghouse and Stone & Webster, Inc. (the "Consortium"). Pursuant to the EPC Agreement, the Consortium will supply, construct, test, and start up two 1,117 MW nuclear generating units utilizing Westinghouse's AP 1000 standard plant design. On October 27, 2015, the Authority and SCE&G executed a Limited Agency Agreement that appointed SCE&G to act as the Authority's agent in connection with an amendment to the EPC Agreement (the "October 2015 Amendment"). The October 2015 Amendment, which became effective on December 31, 2015 and is described in more detail below under "*October 2015 Amendment to the EPC Agreement*", included an irrevocable option (the "Fixed Price Option") which SCE&G executed on behalf of the Owners on July 1, 2016, 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% portion being approximately $2.737 billion), subject to adjustment for amounts paid since June 30, 2015. Under the Fixed Price Option, the aggregate delay-related liquidated damages amount are capped at $338.0 million per Unit (the Authority's 45% portion being approximately $152.0 million per Unit), and the completion bonus amounts are $150.0 million per Unit (the Authority's 45% portion being approximately $68.0 million per Unit).

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 guarantees, as well as certain bonuses payable to the Consortium for schedule 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. However, see "*Other Recent Project Developments*" herein for information regarding the recently disclosed negative impact on Toshiba's financial results as a result of the impairment of several billions of U.S. dollars.

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) failure by either SCE&G or the Authority to make payment to the Consortium in accordance with the EPC Agreement requirements, (ii) breach by either SCE&G or the Authority of a material provision of the EPC Agreement, or (iii) insolvency of either SCE&G or the Authority unless the other of SCE&G or the Authority has provided security for payments that would be due from such insolvent entity.

EPC Agreement History. Pursuant to the May 23, 2008 EPC Agreement (the "2008 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 bonuses, and adjustments for cost overruns. A majority of the 2008 EPC Agreement costs are fixed or firm. In addition to 2008 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. In 2012, the COL was issued and the Authority's Board of Directors approved a budget for construction costs associated with a 45% ownership interest of approximately $5.1 billion including related transmission and initial nuclear fuel cores. In October 2015 the Authority and SCE&G executed an agreement with the Consortium to resolve certain disputed matters and amend the 2008 EPC Agreement. See "*October 2015 Amendment to the EPC Agreement*" for additional details.

October 2015 Amendment to the EPC Agreement. On October 27, 2015, the EPC Agreement was amended. 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 Chicago Bridge and Iron Company ("CB&I"). Stone & Webster continues 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% 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% 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% 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% 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% 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. See "*Other Recent Project Developments*" for additional details.

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 ("DRB") 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.

The October 2015 Amendment provides the Owner an irrevocable option ("Fixed Price 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 an agreed upon list of items under review, and 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% portion being approximately $2.737 billion). This total amount to be paid would be subject to adjustment for amounts paid since June 30, 2015. Under the Fixed Price Option, the aggregate delay-related liquidated damages amount referred to in (iii) above would be capped at $338.0 million per Unit (Authority's 45% 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% portion being approximately $68.0 million per Unit). SCE&G had previously informed the PSC that it had notified Westinghouse that it would elect the Fixed Price Option under the October 2015 Amendment, subject to formal concurrence by the Authority and the approval of the PSC. The Limited Agency Agreement dated October 27, 2015 provides that the Authority must give SCE&G its prior written consent before SCE&G may exercise the Fixed Price Option. On June 30, 2016, the Authority's Board of Directors adopted a resolution authorizing the President and CEO of the Authority to execute a Limited Agency Agreement with SCE&G that appoints SCE&G to act as the Authority's agent in connection with the exercise of the Fixed Price Option. In addition, the Board approved a $1.1 billion increase in the Authority's construction budget for the Project from the $5,148,948,000 approved by the Board on April 5, 2012 to $6,248,948,000. On July 1, 2016, SCE&G executed, on behalf of the Owners, the Fixed Price Option in accordance with the requirements of Section 2 of the October 2015 Amendment. On November 28, 2016, the PSC approved SCE&G's execution of the Fixed Price Option.

Finally, as noted above, the October 2015 Amendment provides for the development of a revised construction milestone payment schedule and establishes a DRB process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule. The October 2015 Amendment provides that if the parties are unable to agree upon the revised construction milestone payment schedule by July 1, 2016, then, unless the parties agree or the process is otherwise delayed, the matter will be referred to the DRB. The parties were unable to reach an agreement by July 1, 2016 and as a result, in accordance with the terms of the October 2015 Amendment, the Owner referred the matter to the DRB on August 1, 2016, and the DRB held a hearing on the dispute. The October 2015 Amendment provides that the DRB shall issue its report on the construction milestone payment schedule within 60 days and that for the 60-day period of DRB review, the Owner will pay the Consortium $100.0 million per month in lieu of all other payments (Authority's 45% portion being $45.0 million per month).

On September 30, 2016, the DRB issued an Order directing the parties to develop a milestone payment schedule subject to certain parameters. The DRB's Order also provided that the Owner shall pay to the Consortium for the months of October and November, 2016, the amounts of $133.0 million and $136.5 million, respectively. The parties were unable to reach agreement and after further hearings, the DRB made its final determination and issued an order on December 2, 2016 establishing the Construction Milestone Payment Schedule ("CMPS"). The Authority began making payments pursuant to the CMPS in December 2016.

Substantial Completion Dates and EPC Project Schedule. As outlined in the table "Summary of Substantial Completion Dates" below, there have been several proposed and approved contractual schedule modifications since 2008.

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 - Rebaselined Schedule - August 2014	December 2018 - June 2019 (+12 to +15 months)	June 2020 (+15 months)
EPC - October 2015 Amendment	August 31, 2019 (+2 to +8 months)	August 31, 2020 (+2 months)

Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated 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 guaranteed 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 continued to experience 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 were not accepted as revised contractual substantial completion dates, and the Consortium continued to experience delays.

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. In early August 2014, SCE&G and the Authority received preliminary schedule information in which the Consortium indicated the substantial completion of Unit 2 was 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.

Subsequent to 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. This figure was presented as a total project cost in 2007 dollars subject to escalation and did 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 worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium indicated that the Unit 2 substantial completion date was expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. The dates were not accepted as revised contractual substantial completion dates.

On October 27, 2015 the parties amended the EPC which included revised substantial completion dates for Unit 2 and Unit 3 of August 31, 2019 and 2020, respectively. See "*Other Recent Project Developments*" below for additional information on the estimated substantial completion dates.

Construction. Phase I of the construction commenced May 23, 2008 upon 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. 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 a number of key construction milestones were achieved in 2016 as detailed below:

Summer Nuclear Unit 2	
Set Structural Module CA03 (IRWST)	July 20, 2016
Set Structural Module CA02 (IRWST/Pressurizer Wall)	August 5, 2016
Set Reactor Vessel	August 30, 2016
Set Generator Stator	October 25, 2016

Summer Nuclear Unit 3	
Set Structural Module CA20 Subassemblies 3&4	March 12, 2016
Set Containment Vessel Ring 1	April 13, 2016
Set Structural Module CA05	May 2, 2016
Set Structural Module CA20 Subassemblies 1&2	August 16, 2016
Set Shield Building Horizontal Transition Panels	November 9, 2016
Set Structural Module CA01 (Steam Generator & Refueling Canal)	December 16, 2016

The following table sets forth the current status of the project components.

Project Component	% Complete
Engineering	94
Procurement	83
Construction	30

Other Recent Project Developments. In late 2015, Toshiba Corporation's ("Toshiba") credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity, pursuant to the above-described terms of the EPC Contract, the Owners obtained payment and performance bonds from Westinghouse in the form of standby letters of credit totaling $45.0 million (or approximately $20.0 million of the Authority's 45% share). These standby letters of credit expire annually and automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew its letter of credit. In the event that Westinghouse is unable to meet its payment and performance obligations under the EPC Contract, it is anticipated that the letters of credit will provide a source of liquidity to assist in an orderly transition and in enabling construction activities to continue. In addition, the EPC Contract provides that upon request of the Owners, the Consortium must escrow certain intellectual property for the benefit of the Owners to enable completion of the Summer Nuclear Units 2 and 3. An escrow agreement and account was established in December 2016 and is currently being populated with pertinent intellectual property and software to enable completion of the units.

Toshiba has encountered continued financial difficulties related to the goodwill associated with the Westinghouse acquisition of Stone & Webster. On February 14, 2017, Toshiba requested an extension to March 14, 2017 for it to submit its quarterly securities report for the period covering October 1, 2016 to December 31, 2016 and announced in its provisional forecast (unaudited) that its goodwill impairment loss for the third quarter ended December 31, 2016 is 712.5 billion Yen (US $6.3 billion). On February 14, 2017, in addition to reaffirming that the contractor was committed to completing Summer Units 2 and 3, Westinghouse provided SCE&G with revised in-service dates of April 2020 and December 2020 for Summer Units 2 and 3, respectively. Westinghouse intends to make the complete integrated project schedule supporting these dates available for SCE&G and the Authority to review. The Authority and SCE&G cannot determine the reliability of these dates nor predict the outcome of these matters, and are continuing to monitor developments for potential impacts to the construction schedule and costs.

In addition to the above-described project issues, financial difficulties have been experienced by Mangiarotti S.p.A. ("Mangiarotti"), an Italy based supplier responsible for certain significant components of the project. 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 by mid-2017. Since first becoming aware of these financial difficulties, the Consortium has monitored, and continues to monitor, the potential for disruptions in such equipment fabrication and possible responses.

Nuclear Construction - Risk Factors. The construction of large generating plants such as Summer Nuclear Units 2 and 3 involves significant financial and construction risk. Delays and cost overruns have been incurred, and may continue to be incurred, as a result of certain related 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) financial wherewithal and 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 and the completion date of any new nuclear plant is inherently uncertain.

To mitigate potential risks, 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. NND representatives make frequent visits and work closely with the Consortium to monitor progress and issues (engineering, labor, supplier issues, etc.) associated with the AP 1000 nuclear power units currently under construction in China, as well as the units currently under development at nearby Plant Vogtle in Waynesboro, Georgia. A construction oversight review board ("CORB") was formed in 2016 to provide independent oversight of the construction of Units 2 and 3. The board consists of six industry experts that perform quarterly reviews and make recommendations for improvements on all aspects of the project, including licensing, engineering, procurement, construction and testing.

The terms of the amended EPC agreement also provide additional risk mitigation. The risk of additional costs to the Authority and SCE&G resulting from delays is mitigated by increased delay related liquidated damages and the Fixed Price Option. Finally, the Authority has sufficient generating capacity to manage delays of the units coming online and the ability to pass fuel cost differentials to its customers through its existing rates. The Authority's Board also has autonomous rate making authority and the Authority's largest wholesale power sale contract, accounting for over 50% of its revenues, automatically adjusts for changes in costs, including debt service. In addition, O&M costs associated with Summer Nuclear Units 2 and 3, currently in the Authority's rate forecast, will not be incurred during any delay period, partially offsetting fuel cost differentials.

Financing Activities

Traditionally, the Authority has amortized its debt taking into consideration the potential termination of the Central Agreement 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 $650.0 million of its existing debt.

The Authority's construction budget associated with a 45 percent ownership interest in the Summer Nuclear Units 2 and 3 is approximately $6.2 billion. This reflects the additional cost associated with exercising the Fixed Price Option and includes approximately $220.0 million for transmission and approximately $139.0 million for the initial fuel core and the remaining $5.9 billion for construction of the units. In addition, since inception the Authority has capitalized approximately $374.1 million of the interest on debt issued to finance the project. To date, the Authority has financed approximately $4.2 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 2017 through 2020 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 Obligation Bonds 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, 2016, Santee Cooper had $1.8 billion of cash and investments, of which $816.7 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $217.7 million.

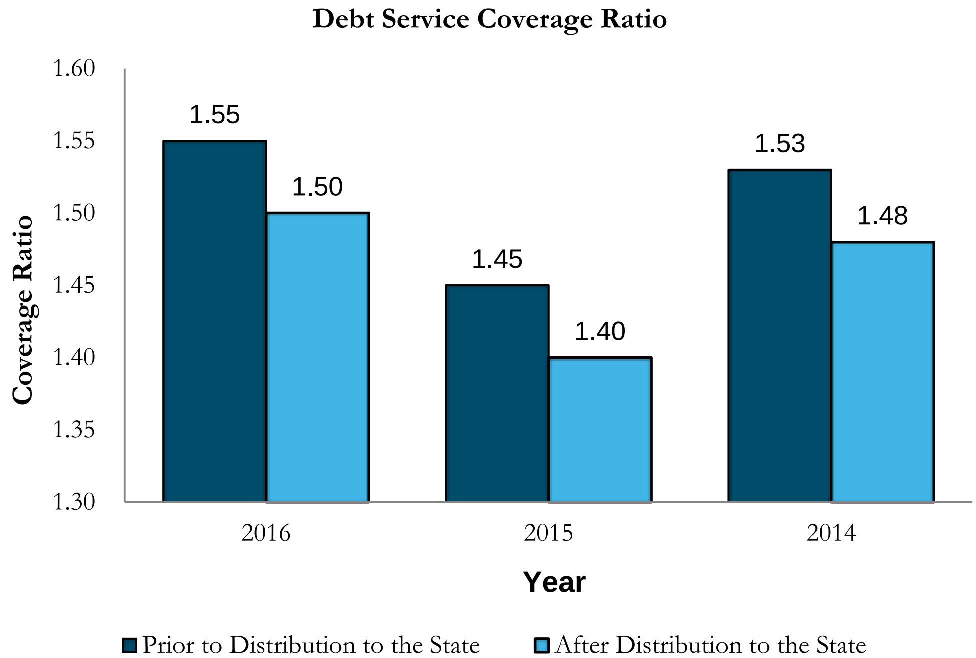
Revolving credit agreements used to support the issuance of commercial paper totaled $750.0 million at December 31, 2016. The agreements with five banks mature at various dates in 2017 and 2018 and management expects to renew or replace the agreements as needed prior to expiration.

To obtain other funds, the Authority entered into a new Revolving Credit Agreement with Barclays Bank PLC. This agreement allows the Authority to borrow up to $200.0 million and expires on November 27, 2019. In August 2016, the Authority secured a $100.0 million loan under the Direct Purchase Revolving Credit Agreement to pay off $100.0 million of Commercial Paper Notes.

Net cash used by the Authority during 2016 was $103.9 million. This decrease in cash was due to net cash provided by operating and investing activities of $713.7 million and $185.0 million, respectively, offset by cash used in financing activities of $1.0 billion.

Debt Service Coverage

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2016, 2015 and 2014 is shown below:



Bond Ratings

Bond ratings assigned by various agencies for the years ended December 31, 2016, 2015 and 2014 were as follows:

Agency / Lien Level	2016	2015	2014
Fitch Ratings			
Revenue Obligations	**A+**	A+	A+
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**	N/A	SP-1+

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Bond Market Transactions for Years 2016, 2015 and 2014

YEAR 2016

Revenue Obligations:	**2016 Tax-exempt Refunding Series A**	**Par Amount:**	$ 543,745,000
Purpose:	Refund a portion of the following: 2007 Series A, 2008 Series A, 2009 Refunding Series A, 2009 Series B, and 2014 Series A	**Date Closed:**	February 10, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.66 percent		
Revenue Obligations:	**2016 Series M1 - Current Interest Bearing Bonds (CIBS)**	**Par Amount:**	$ 33,282,500
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	May 19, 2016
Comments:	Tax-exempt minibonds		
Revenue Obligations:	**2016 Series M1 – Capital Appreciation Bonds (CABS)**	**Par Amount:**	$ 8,860,200
Purpose:	To finance a portion of the Authority's ongoing capital program	**Date Closed:**	May 19, 2016
Comments:	Tax-exempt minibonds		
Revenue Obligations:	**2016 Tax-exempt Refunding and Improvement Series B**	**Par Amount:**	$ 508,705,000
Purpose:	To finance a portion of the Authority's ongoing capital program and refund a portion of the following: 2009 Series E	**Date Closed:**	July 20, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.75 percent		
Revenue Obligations:	**2016 Taxable Series D**	**Par Amount:**	$ 322,650,000
Purpose:	To retire certain Commercial Paper Notes and to finance a portion of the Authority's ongoing capital program	**Date Closed:**	July 20, 2016
Comments:	Taxable bonds with an all-in true interest cost of 2.45 percent		
Revenue Obligations:	**2016 Tax-exempt Refunding Series C**	**Par Amount:**	$ 52,400,000
Purpose:	Refund a portion of the following: 2006 Series C	**Date Closed:**	October 13, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.11 percent		

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		

Bond Market Transactions for Years 2016, 2015 and 2014

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		

Cherry Bekaert LLP
CPAs & Advisors

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, 2016 and 2015, 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, 2016 and 2015, 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 Notes 7 and 16 to the basic financial statements, as it relates to the construction of the Summer Nuclear Units 2 and 3, recent developments have caused uncertainty as to whether Westinghouse will be able to meet its obligations under the Engineering, Procurement and Construction contract. 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 Reporting Required by Government Auditing Standards
In accordance with Government Auditing Standards, we have also issued our report dated March 1, 2017 on our consideration of the Authority's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, grant agreements and other matters. The purpose of the 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 in considering the Authority's internal control over financial reporting and compliance.

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.

Cherry Bekaert LLP

Raleigh, North Carolina
March 1, 2017

Combined Statements of Net Position

South Carolina Public Service Authority
As of December 31, 2016 and 2015

	2016	2015
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	**$ 90,873**	$ 113,413
Unrestricted investments	**725,865**	531,120
Restricted cash and cash equivalents	**87,524**	168,930
Restricted investments	**792,490**	1,165,630
Receivables, net of allowance for doubtful accounts of $2,179 and $1,662 at December 31, 2016 and 2015, respectively	**198,532**	175,931
Materials inventory	**131,678**	126,259
Fuel inventory		
Fossil fuels	**419,332**	507,716
Nuclear fuel-net	**164,960**	161,990
Interest receivable	**3,425**	3,357
Prepaid expenses and other current assets	**164,487**	200,925
Total current assets	**2,779,166**	3,155,271
Noncurrent assets		
Restricted cash and cash equivalents	**251**	205
Restricted investments	**130,925**	126,282
Capital assets		
Utility plant	**7,271,505**	7,134,706
Long lived assets-asset retirement cost	**265,116**	507,394
Accumulated depreciation	**(3,620,430)**	(3,476,246)
Total utility plant-net	**3,916,191**	4,165,854
Construction work in progress	**4,292,907**	3,337,353
Other physical property-net	**5,689**	5,914
Investment in associated companies	**6,569**	7,001
Unamortized debt expenses	**40,302**	39,249
Costs to be recovered from future revenue	**234,215**	240,923
Regulatory asset-asset retirement obligation	**672,036**	699,748
Other noncurrent and regulatory assets	**159,978**	215,987
Total noncurrent assets	**9,459,063**	8,838,516
Total assets	**$ 12,238,229**	$ 11,993,787
DEFERRED OUTFLOWS OF RESOURCES		
Deferred outflows – pension	**$ 51,616**	$ 31,430
Accumulated decrease in fair value of hedging derivatives	**39,630**	91,372
Unamortized loss on refunded and defeased debt	**180,349**	133,932
Total deferred outflows of resources	**$ 271,595**	$ 256,734
Total assets & deferred outflows of resources	**$ 12,509,824**	$ 12,250,521

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, 2016 and 2015

	2016	2015
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long-term debt	**$ 134,055**	$ 172,896
Accrued interest on long-term debt	**54,418**	67,378
Commercial paper	**399,899**	597,520
Accounts payable	**233,645**	362,755
Other current liabilities	**94,550**	99,042
Total current liabilities	**916,567**	1,299,591
Noncurrent liabilities		
Construction liabilities	**11,059**	6,643
Net pension liability	**324,956**	286,300
Asset retirement obligation liability	**739,821**	1,046,054
Total long-term debt (net of current portion)	**7,661,497**	6,961,336
Unamortized debt discounts and premiums	**473,419**	345,133
Long-term debt-net	**8,134,916**	7,306,469
Other credits and noncurrent liabilities	**110,099**	130,192
Total noncurrent liabilities	**9,320,851**	8,775,658
Total liabilities	**$ 10,237,418**	$ 10,075,249
DEFERRED INFLOWS OF RESOURCES		
Deferred inflows - pension	**$ 13,582**	$ 17,424
Accumulated increase in fair value of hedging derivatives	**9,991**	4,701
Nuclear decommissioning costs	**218,497**	211,357
Total deferred inflows of resources	**$ 242,070**	$ 233,482
NET POSITION		
Net invested in capital assets	**$ 1,168,907**	$ 1,195,402
Restricted for debt service	**39,158**	79,771
Restricted for capital projects	**1,663**	4,304
Unrestricted	**820,608**	662,313
Total net position	**$ 2,030,336**	$ 1,941,790
Total liabilities, deferred inflows of resources & net position	**$ 12,509,824**	$ 12,250,521

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Combined Statements of Revenues, Expenses and Changes in Net Position

South Carolina Public Service Authority
Years Ended December 31, 2016 and 2015

	2016	2015
	(Thousands)	
Operating revenues		
Sale of electricity	$ **1,721,108**	$ 1,856,523
Sale of water	**8,230**	8,069
Other operating revenue	**16,319**	14,961
Total operating revenues	**1,745,657**	1,879,553
Operating expenses		
Electric operating expenses		
Production	**137,166**	123,421
Fuel	**632,171**	713,308
Purchased and interchanged power	**143,566**	193,646
Transmission	**24,516**	26,749
Distribution	**10,999**	11,216
Customer accounts	**16,745**	15,316
Sales	**9,891**	13,476
Administrative and general	**94,022**	88,899
Electric maintenance expenses	**119,847**	131,331
Water operating expenses	**3,005**	2,864
Water maintenance expenses	**1,068**	910
Total operating and maintenance expenses	**1,192,996**	1,321,136
Depreciation	**177,004**	176,039
Sums in lieu of taxes	**4,942**	5,313
Total operating expenses	**1,374,942**	1,502,488
Operating income	**370,715**	377,065
Nonoperating revenues (expenses)		
Interest and investment revenue	**13,001**	9,207
Net decrease in the fair value of investments	**(1,635)**	(4,455)
Interest expense on long-term debt	**(239,672)**	(282,564)
Interest expense on commercial paper and other	**(3,896)**	(3,033)
Amortization expense	**14,391**	6,494
Costs to be recovered from future revenue	**(6,708)**	(6,435)
U.S. Treasury subsidy on Build America Bonds	**7,575**	7,559
Other-net	**(46,033)**	(49,323)
Total nonoperating revenues (expenses)	**(262,977)**	(322,550)
Income before transfers	**107,738**	54,515
Capital contributions & transfers		
Distribution to the State	**(19,192)**	(20,116)
Total capital contributions & transfers	**(19,192)**	(20,116)
Change in net position	**88,546**	34,399
Net position-beginning of period as previously reported	**1,941,790**	2,168,463
Restatement (Note 15)	**0**	(261,072)
Total net position-beginning of period as restated	**1,941,790**	1,907,391
Total net position-ending	$ **2,030,336**	$ 1,941,790

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, 2016 and 2015

	2016	2015
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	**$ 1,722,539**	$ 1,890,839
Payments to non-fuel suppliers	**(380,450)**	(787,254)
Payments for fuel	**(624,554)**	(703,519)
Purchased power	**(143,566)**	(193,646)
Payments to employees	**(185,588)**	(175,633)
Other receipts-net	**325,296**	206,834
Net cash provided by operating activities	**713,677**	237,621
Cash flows from non-capital related financing activities		
Distribution to the State	**(19,192)**	(20,116)
Proceeds from sale of bonds	**78,011**	13,150
Proceeds from long-term revolving credit agreement draw	**100,000**	0
Proceeds from issuance of commercial paper notes	**78,115**	180,885
Repayment of commercial paper notes	**(238,607)**	(13,986)
Refunding/defeasance of long-term debt	**(80,555)**	(14,065)
Repayment of long-term debt	**(260)**	(119)
Interest paid on long-term debt	**(9,433)**	(8,383)
Interest paid on commercial paper and other	**(6,204)**	(4,321)
Bond issuance and other related costs	**2,726**	694
Net cash (used in) provided by non-capital related financing activities	**(95,399)**	133,739
Cash flows from capital-related financing activities		
Proceeds from sale of bonds	**1,391,631**	1,426,644
Proceeds from issuance of commercial paper notes	**58,974**	65,201
Repayment of commercial paper notes	**(96,103)**	(44,719)
Refunding/defeasance of long-term debt	**(670,925)**	(659,490)
Repayment of long-term debt	**(159,529)**	(139,132)
Interest paid on long-term debt	**(362,102)**	(338,020)
Interest paid on commercial paper and other	**(1,336)**	(905)
Construction and betterments of utility plant	**(1,126,306)**	(587,228)
Bond issuance and other related costs	**87,450**	100,264
Other-net	**(28,981)**	(31,879)
Net cash used in capital related financing activities	**(907,227)**	(209,264)
Cash flows from investing activities		
Net decrease (increase) in investments	**172,117**	(348,516)
Interest on investments	**12,932**	7,637
Net cash provided by (used in) investing activities	**185,049**	(340,879)
Net decrease in cash and cash equivalents	**(103,900)**	(178,783)
Cash and cash equivalents-beginning	**282,548**	461,331
Cash and cash equivalents-ending	**$ 178,648**	$ 282,548

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, 2016 and 2015

	2016	2015
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	**$ 370,715**	$ 377,065
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation	**177,004**	176,039
Amortization of nuclear fuel	**28,125**	22,832
Net power gains involving associated companies	**(35,616)**	(47,366)
Distributions from associated companies	**31,749**	44,864
Advances to associated companies	**(36)**	162
Other income and expenses	**(31,901)**	(37,049)
Changes in assets and liabilities		
Accounts receivable-net	**(22,601)**	11,393
Inventories	**82,965**	(186,692)
Prepaid expenses	**65,874**	32,845
Other deferred debits	**41,139**	(48,474)
Accounts payable	**(8,943)**	(140,604)
Other current liabilities	**(1,881)**	(31,070)
Other noncurrent liabilities	**17,084**	63,676
Net cash provided by operating activities	**$ 713,677**	$ 237,621

	2016	2015
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	**$ 90,873**	$ 113,413
Restricted cash and cash equivalents	**87,524**	168,930
Noncurrent		
Restricted cash and cash equivalents	**251**	205
Cash and cash equivalents at the end of the year	**$ 178,648**	$ 282,548

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 or invested in capital assets, net of related debt, 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 $187.7 million and $43.5 million of interest in 2016 and 2015, respectively. The 2016 amount includes $61.3 million transferred from a deferred interest account to capitalized interest. 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,	**2016**	2015
Annual average depreciation percentages	**2.5%**	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,		**2016**			2015	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 693.5**	**$ 352.5**	**$ 1,046.0**	$ 678.8	$ 364.8	$ 1,043.6
Accretion expense	**(289.6)**	**(16.5)**	**(306.1)**	14.7	(12.3)	2.4
Balance as of December 31,	**$ 403.9**	**$ 336.0**	**$ 739.9**	$ 693.5	$ 352.5	$ 1,046.0
Asset Retirement Cost (ARC):	**$ 92.0**	**$ 173.1**	**$ 265.1**	$ 334.3	$ 173.1	$ 507.4

J - Reporting Impairment Losses - The Authority's Board authorized the retirement of six generating units during 2012. Four coal-fired units, (Grainger Units 1 and 2, and Jefferies Units 3 and 4) were permanently retired December 2012. Two coal-fired units (Jefferies Units 1 and 2) were permanently retired October 2015. 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.

At the end of 2016, Grainger Units 1 and 2 dismantling and sale of scrap was completed. In addition, the Authority completed sale of the existing coal (fuel stock pile) from both Grainger and Jefferies generating stations in 2016. The Authority is also preparing for future sale of generating station assets for Jefferies Units 1, 2, 3 and 4.

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 seven-year period ending December 2020. Accordingly, $42.5 million was written off in both 2016 and 2015. The remaining balance outstanding at December 31, 2016 was $170.1 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,	**2016**	2015
Owners	Ownership (%)	
City Utilities of Springfield (Missouri)	**5.55**	5.55
Cowlitz Public Utility District (Washington)	**5.55**	5.55
Gainesville Regional Utilities (Florida)	**5.55**	5.55
American Municipal Power (Ohio)	**16.67**	16.67
JEA (Florida)	**16.67**	16.67
MEAG Power (Georgia)	**16.67**	16.67
Nebraska Public Power District (Nebraska)	**16.67**	16.67
Santee Cooper (South Carolina)	**16.67**	16.67
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,	**2016**	2015
	(Thousands)	
TEA Investment:		
Balance as of January 1,	**$ 6,858**	$ 8,281
Reduction to power costs and increases in electric revenues	**31,281**	43,809
Less: Distributions from TEA	**31,734**	44,864
Less: Other (includes equity losses)	**14**	368
Balance as of December 31,	**$ 6,391**	$ 6,858
Due To/Due From TEA:		
Payable to	**$ 21,259**	$ 26,839
Receivable from	**$ 1,672**	$ 3,245

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, 2016, the trade guarantees are an amount not to exceed approximately $84.5 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. 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, 2016 and 2015 was $0 and $5,000, respectively.

The Authority is also a member of TEA Solutions. TEA Solutions is a publicly supported non-profit corporation. Members and ownership interests were as follows:

Years Ended December 31,	2016	2015
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, 2016 and 2015 was approximately $179,000 and $122,000, 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,	2016	2015
	(Thousands)	
Deferred outflows of resources	**$ 271,595**	$ 256,734
Deferred inflows of resources	**$ 242,070**	$ 233,482

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, 2016 and 2015 is below:

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			**2016**		2015
	Account Classification		(Millions)		
Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**(31.0)**	$	(84.5)
Heating oil	Regulatory assets/liabilities		**1.4**		(2.2)
Changes in Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**53.5**	$	(24.2)
Heating oil	Regulatory assets/liabilities		**3.6**		6.4
Recognized Net Gains (Losses)					
Natural gas	Operating expense-fuel	**$**	**(38.5)**	$	(44.6)
Heating oil	Operating expense-fuel		**(1.6)**		(11.0)
Realized But Not Recognized Net Gains (Losses)					
Natural gas	Regulatory assets/liabilities	**$**	**(5.0)**	$	(8.8)
Heating oil	Regulatory assets/liabilities		**(0.1)**		(0.2)
Notional					
			MBTUs		
Natural gas			**102,192**		107,033
			Gallons (000s)		
Heating oil			**7,098**		6,930
Maturities					
Natural gas			**Jan 2017-Dec 2021**		Jan 2016-Dec 2020
Heating oil			**Jan 2017-Dec 2018**		Jan 2016-Dec 2016

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 $14.5 million in 2016 and $13.0 million in 2015.

Fuel costs are reflected in operating expenses as fuel is consumed. All customers are billed utilizing rates and contracts that include fuel cost recovery components, the majority of which include monthly automatic fuel adjustment provisions which provide for adjustments to the base rates to cover increases or decreases in the cost of fuel to the extent such costs vary from the predetermined base rates. The fuel adjustment provisions are based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period.

Rates to Central are determined in accordance with the cost of service methodology contained in the Central Agreement. Under this agreement Central initially pays monthly based on estimated rates and actual loads. The charges are then adjusted to reflect actual costs and loads, on a monthly basis for fuel and an annual basis for all other costs, and Central is charged or credited with the difference.

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 2016 and 2015 totaled approximately $19.2 million and $20.1 million, respectively.

R - New Accounting Standards

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 68	**Accounting and Financial Reporting for Pensions - an amendment of GASB Statement No. 27**	Implemented in 2015
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.	
Statement No. GASB 71	**Pension Transition for Contributions Made Subsequent to the Measurement Date - an amendment of GASB Statement No. 68**	Implemented in 2015
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, *Accounting and Financial Reporting for Pensions*. 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.	
Statement No. GASB 72	**Fair Value Measurement and Application**	Implemented in 2016
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 *fair value* 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.	
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**	Reviewed and no action required
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, *Accounting and Financial Reporting for Pensions*, 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, *Financial Reporting for Pension Plans* and Statement 68 for pension plans and pensions that are within their respective scopes.	

Statement No. GASB 74 | **Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans** | Under review

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, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*, as amended, and No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*. It also includes requirements for defined contribution OPEB plans that replace the requirements for those OPEB plans in Statement No. 25, *Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans*, as amended, Statement 43, and Statement No. 50, *Pension Disclosures*.

Statement No. GASB 75 | **Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions** | Under review

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, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, as amended, and No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*, for OPEB. Statement No. 74, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*, establishes new accounting and financial reporting requirements for OPEB plans.

Statement No. GASB 76 | **The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments** | Reviewed and no action required

Issue Date: June 2015 | Effective for Periods Beginning After: June 15, 2015

Description:

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.

This Statement supersedes Statement No. 55, *The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments*. 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.

Statement No. GASB 77 | **Tax Abatement Disclosures** | Reviewed and no action required

Issue Date: August 2015 | Effective for Periods Beginning After: December 15, 2015

Description:

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.

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.

Statement No. GASB 78	**Pensions Provided Through Certain Multiple-Employer Defined Benefit Pension Plans**	Reviewed and no action required
Issue Date: December 2015	Effective for Periods Beginning After: December 15, 2015	
Description:	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.	
Statement No. GASB 79	**Certain External Investment Pools and Pool Participants**	Reviewed and no action required
Issue Date: December 2015	Effective for Periods Beginning After: June 15, 2015	
Description:	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.	
Statement No. GASB 80	**Blending Requirements for Certain Component Units—an amendment of GASB Statement 14**	Under review
Issue Date: January 2016	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to improve financial reporting by clarifying the financial statement presentation requirements for certain component units. This Statement amends the blending requirements established in paragraph 53 of Statement No. 14, *The Financial Reporting Entity, as amended.* This Statement amends the blending requirements for the financial statement presentation of component units of all state and local governments. The additional criterion requires blending of a component unit incorporated as a not-for-profit corporation in which the primary government is the sole corporate member. The additional criterion does not apply to component units included in the financial reporting entity pursuant to the provisions of Statement No. 39, *Determining Whether Certain Organizations Are Component Units*.	
Statement No. GASB 81	**Irrevocable Split-Interest Agreements**	Under review
Issue Date: March 2016	Effective for Periods Beginning After: December 15, 2016	
Description:	The objective of this Statement is to improve accounting and financial reporting for irrevocable split-interest agreements by providing recognition and measurement guidance for situations in which a government is a beneficiary of the agreement. Split-interest agreements are a type of giving agreement used by donors to provide resources to two or more beneficiaries, including governments. Split-interest agreements can be created through trusts—or other legally enforceable agreements with characteristics that are equivalent to split-interest agreements—in which a donor transfers resources to an intermediary to hold and administer for the benefit of a government and at least one other beneficiary. Examples of these types of agreements include charitable lead trusts, charitable remainder trusts, and life-interests in real estate. This Statement requires that a government that receives resources pursuant to an irrevocable split-interest agreement recognize assets, liabilities, and deferred inflows of resources at the inception of the agreement. Furthermore, this Statement requires that a government recognize assets representing its beneficial interests in irrevocable split-interest agreements that are administered by a third party, if the government controls the present service capacity of the beneficial interests. This Statement requires that a government recognize revenue when the resources become applicable to the reporting period.	

Statement No. GASB 82	**Pension Issues—an amendment of GASB Statements No. 67, No. 68, and No. 73**	Under review
Issue Date: March 2016	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to address certain issues that have been raised with respect to Statements No. 67, *Financial Reporting for Pension Plans*, No. 68, *Accounting and Financial Reporting for Pensions*, and No. 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*. Specifically, this Statement addresses issues regarding (1) the presentation of payroll-related measures in required supplementary information, (2) the selection of assumptions and the treatment of deviations from the guidance in an Actuarial Standard of Practice for financial reporting purposes, and (3) the classification of payments made by employers to satisfy employee (plan member) contribution requirements.	
Statement No. GASB 83	**Certain Asset Retirement Obligations**	Under review
Issue Date: November 2016	Effective for Periods Beginning After: June 15, 2018	
Description:	This Statement addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. A government that has legal obligations to perform future asset retirement activities related to its tangible capital assets should recognize a liability based on the guidance in this Statement.	

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,	**2016**	2015
	(Millions)	
CTBR regulatory asset:		
Balance	**$ 234.2**	$ 240.9
CTBR expense/(reduction to expense):		
Net expense	**$ 6.7**	$ 6.4

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2016 and 2015 was as follows:

	Beginning Balances	Increases	Decreases	Ending Balances
		Year 2016 (Thousands)		
Utility plant	**$ 7,134,706**	**$ 181,478**	**$ (44,679)**	**$ 7,271,505**
Long lived assets-asset retirement cost	**507,394**	**0**	**(242,278)**	**265,116**
Accumulated depreciation	**(3,476,246)**	**(213,019)**	**68,835**	**(3,620,430)**
Total utility plant-net	**4,165,854**	**(31,541)**	**(218,122)**	**3,916,191**
Construction work in progress	**3,337,353**	**1,136,928**	**(181,374)**	**4,292,907**
Other physical property-net	**5,914**	**0**	**(225)**	**5,689**
Totals	**$ 7,509,121**	**$ 1,105,387**	**$ (399,721)**	**$ 8,214,787**
		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

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,	**2016**			2015		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 15,234**	**$ 99,820**	**$ 115,054**	$ 23,534	$ 142,892	$ 166,426
Debt Reduction	**5,590**	**103,297**	**108,887**	3,575	53,879	57,454
Funds from Taxable Borrowings	**11,040**	**249,456**	**260,496**	9,216	176,509	185,725
General Improvement	**2,160**	**950**	**3,110**	579	2,448	3,027
Internal Nuclear Decommissioning Fund	**3,337**	**83,189**	**86,526**	2,764	81,230	83,994
Nuclear Fuel	**2,684**	**2,000**	**4,684**	2,701	13,017	15,718
Revenue and Operating	**48,852**	**102,630**	**151,482**	63,811	15,289	79,100
Special Reserve	**1,976**	**84,523**	**86,499**	7,233	45,856	53,089
Total	**$ 90,873**	**$ 725,865**	**$ 816,738**	$ 113,413	$ 531,120	$ 644,533
Current Restricted:						
Debt Service Funds	**$ 60,854**	**$ 32,722**	**$ 93,576**	$ 68,190	$ 78,959	$ 147,149
Funds from Tax-exempt Borrowings	**19,963**	**734,074**	**754,037**	65,069	1,062,535	1,127,604
Other	**6,707**	**25,694**	**32,401**	35,671	24,136	59,807
Total	**$ 87,524**	**$ 792,490**	**$ 880,014**	$ 168,930	$ 1,165,630	$ 1,334,560
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 251**	**$ 130,925**	**$ 131,176**	$ 205	$ 126,282	$ 126,487
Total	**$ 251**	**$ 130,925**	**$ 131,176**	$ 205	$ 126,282	$ 126,487
TOTAL FUNDS	**$ 178,648**	**$ 1,649,280**	**$ 1,827,928**	$ 282,548	$ 1,823,032	$ 2,105,580

Cash and investments as of December 31, consisted of the following:	**2016**	2015
Cash/Deposits	**$ 48,796**	$ 64,639
Investments	**1,779,132**	2,040,941
Total cash and investments	**$ 1,827,928**	$ 2,105,580

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.

Investments are recorded at fair value in accordance with GASB Statement No. 72, Fair Value Measurement and Application. Accordingly, the gains and losses in fair value are 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,	**2016**	2015
Total Portfolio	(Billions)	
Total investments	**$ 1.8**	$ 2.0
Purchases	**23.9**	49.6
Sales	**24.2**	49.4
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 217.4**	$ 210.3
Purchases	**863.8**	697.8
Sales	**856.9**	691.9
Unrealized holding gain/(loss)	**0.3**	(1.7)
Repurchase Agreements (1)	(Millions)	
Balance at December 31	**$ 54.5**	$ 98.9

(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, 2016 and 2015, 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, 2016 and 2015, 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, 2016 and 2015, 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, 2016 and 2015 were as follows:

Security Type / Issuer	Fair Value 2016	Fair Value 2015
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 621,332**	$ 917,423
Federal National Mortgage Association	**241,907**	210,528
Federal Farm Credit Bank	**365,633**	339,001
Federal Home Loan Mortgage Corp	**358,934**	333,923

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 as of December 31, 2016 and 2015:

		Investment Maturities as of December 31, 2016			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
			(Thousands)		
Certificates of Deposits	**$ 950**	**$ 950**	**$ 0**	**$ 0**	**$ 0**
Repurchase Agreements	**54,453**	**54,453**	**0**	**0**	**0**
Federal Agency Discount Notes	**307,774**	**307,774**	**0**	**0**	**0**
Federal Agency Securities	**1,305,998**	**629,651**	**573,496**	**16,611**	**86,240**
US Treasury Bills, Notes and Strips	**109,957**	**88,651**	**3,335**	**0**	**17,971**
	$ 1,779,132	**$ 1,081,479**	**$ 576,831**	**$ 16,611**	**$ 104,211**

		Investment Maturities as of December 31, 2015			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
			(Thousands)		
Certificates of Deposits	$ 1,450	$ 1,450	$ 0	$ 0	$ 0
Repurchase Agreements	98,910	98,910	0	0	0
Federal Agency Discount Notes	413,582	413,582	0	0	0
Federal Agency Securities	1,412,756	1,014,580	281,610	41,120	75,446
US Treasury Bills, Notes and Strips	114,243	19,336	39,457	0	55,450
	$ 2,040,941	$ 1,547,858	$ 321,067	$ 41,120	$ 130,896

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 $40.8 million par in U.S. Treasury Strips ranging in maturity from February 15, 2017 to May 15, 2039. The accounts also hold $54.0 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.

Fair Value of Investments

The Authority measures and records its investments using fair value measurement guidelines established by GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows:

Level 1: Quoted prices for identical investments in active markets;
Level 2: Observable inputs other than quoted market prices; and,
Level 3: Unobservable inputs.

The Authority had the following recurring fair value measurements as of December 31, 2016 and 2015:

		Level		
2016	**Total**	**1**	**2**	**3**
		(Thousands)		
Certificates of Deposits	**$ 950**	**$ 0**	**$ 950**	**$ 0**
Repurchase Agreements	**54,453**	**0**	**54,453**	**0**
Federal Agency Discount Notes	**307,774**	**307,774**	**0**	**0**
Federal Agency Securities	**1,305,998**	**1,305,998**	**0**	**0**
US Treasury Bills, Notes and Strips	**109,957**	**109,957**	**0**	**0**
	$ 1,779,132	**$ 1,723,729**	**$ 55,403**	**$ 0**

		Level		
2015	Total	1	2	3
		(Thousands)		
Certificates of Deposits	$ 1,450	$ 0	$ 1,450	$ 0
Repurchase Agreements	98,910	0	98,910	0
Federal Agency Discount Notes	413,582	413,582	0	0
Federal Agency Securities	1,412,756	1,412,756	0	0
US Treasury Bills, Notes and Strips	114,243	114,243	0	0
	$ 2,040,941	$ 1,940,581	$ 100,360	$ 0

Debt securities classified in Level 1 are valued using prices quoted in active markets for those securities. Certificates of Deposits and Repurchase Agreements classified in Level 2 are valued using pricing based on the securities' relationship to benchmark quoted prices.

Note 5 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2016 and 2015 consisted of the following:

	2016	2015	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2004 Series M (4)	**$ 11,389**	$ 18,382	4.90-5.00	100/Accreted Value
2005 Refunding Series A	**0**	17,705	N/A	N/A
2005 Series M (4)	**4,266**	12,901	4.35	100/Accreted Value
2006 Series M (4)	**8,051**	7,983	4.00-4.20	100/Accreted Value
2006 Refunding Series C	**0**	72,235	N/A	N/A
2007 Series A	**0**	75,885	N/A	N/A
2007 Refunding Series B	**35,825**	50,600	5.00	Non-callable
2008 Tax-exempt Series A	**0**	278,950	N/A	N/A
2008 Taxable Series B	**25,000**	25,000	8.368	P&I Plus Make-Whole Premium
2008 Series M (4)	**21,393**	21,233	3.80-4.80	100/Accreted Value
2009 Tax-exempt Refunding Series A	**60,390**	82,435	3.00-5.00	100
2009 Tax-exempt Series B	**0**	112,210	N/A	N/A
2009 Taxable Series C	**82,395**	84,695	5.04-6.224	P&I Plus Make-Whole Premium
2009 Tax-exempt Series E	**2,285**	100,000	4.75	100
2009 Taxable Series F	**100,000**	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series M1 (4)	**26,493**	26,278	3.50-4.30	100/Accreted Value
2010 Refunding Series B	**128,135**	161,460	4.00-5.00	100
2010 Series M2 (4)	**15,691**	15,523	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)	**23,618**	26,801	3.50-4.80	100/Accreted Value
2011 Refunding Series B	**225,640**	267,615	4.00-5.00	Non-callable
2011 Refunding Series C	**135,855**	135,855	4.375-5.00	100
2011 Series M2 (4)	**20,228**	22,023	2.70-4.20	100/Accreted Value
2012 Refunding Series A	**82,060**	86,500	3.00-5.00	100
2012 Refunding Series B	**19,200**	21,200	5.00	Non-callable
2012 Refunding Series C	**60,435**	70,500	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)	**20,869**	20,855	1.40-4.00	100/Accreted Value
2012 Series M2 (4)	**18,063**	18,120	1.10-3.70	100/Accreted Value
2013 Series M1 (4)	**23,152**	23,276	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 Tax-exempt Series E	**506,765**	506,765	5.00-5.50	100
2014 Series M1 (4)	**39,883**	39,701	1.75-4.30	100/Accreted Value
2014 Tax-exempt Series A	**525,000**	600,000	5.00-5.50	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	**594,380**	598,960	3.00-5.00	100
2015 Tax-exempt Refunding Series B	**64,870**	64,870	5.00	Non-callable
2015 Series M1 (4)	**36,508**	36,294	1.75-3.85	100/Accreted Value
2015 Tax-exempt Refunding Series C	**246,635**	270,170	5.00	Non-callable
2015 Taxable Series D	**169,657**	169,657	4.77	P&I Plus Make-Whole Premium
2015 Tax-exempt Series E	**300,000**	300,000	5.25	100

	2016	2015	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
2016 Tax-exempt Refunding Series A	**543,745**	0	3.125-5.00	100
2016 Series M1 (4)	**42,326**	0	1.65-3.75	100/Accreted Value
2016 Tax-exempt Refunding Series B	**508,705**	0	2.25-5.25	100
2016 Tax-exempt Refunding Series C	**52,400**	0	3.00-5.00	100
2016 Taxable Series D	**322,650**	0	2.388	P&I Plus Make-Whole Premium
Total Revenue Obligations	**7,695,552**	7,134,232		
Long-Term Revolving Credit Agreement: (matures in 2018)	**100,000**	0	Variable	
Less: Current Portion - Long-term Debt	**134,055**	172,896		
Total Long-term Debt - (Net of current portion)	**$ 7,661,497**	$ 6,961,336		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2016.

(2) Call Price may only apply to certain maturities outstanding at December 31, 2016.

(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, 2016 and 2015 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 2016 (Thousands)				
Revenue Obligations	**$ 7,134,232**	**$ 1,472,590**	**$ (911,270)**	**$ 7,695,552**	**$ 134,055**	**$ 7,561,497**	**$ 473,419**	**$ 8,034,916**
Long-Term Revolving Credit Agreement	**0**	**100,000**	**0**	**100,000**	**0**	**100,000**	**0**	**100,000**
Totals	**$ 7,134,232**	**$ 1,572,590**	**$ (911,270)**	**$ 7,795,552**	**$ 134,055**	**$ 7,661,497**	**$ 473,419**	**$ 8,134,916**
				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

Summary of Long-Term Principal and Interest

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

Year Ending December 31,	**Revenue Obligations**	**Long-Term Revolving Credit Agreement**	**Total Principal**	**TOTAL INTEREST (1)**	**TOTAL**
			(Thousands)		
2017	$ 116,707	$ 0	$ 116,707	$ 372,670	$ 489,377
2018	119,736	100,000	219,736	365,887	585,623
2019	202,640	0	202,640	359,202	561,842
2020	182,051	0	182,051	350,906	532,957
2021	229,378	0	229,378	342,783	572,161
2022-2026	1,020,387	0	1,020,387	1,586,037	2,606,424
2027-2031	756,670	0	756,670	1,413,139	2,169,809
2032-2036	972,136	0	972,136	1,221,966	2,194,102
2037-2041	841,172	0	841,172	987,869	1,829,041
2042-2046	1,198,035	0	1,198,035	741,352	1,939,387
2047-2051	1,233,380	0	1,233,380	404,068	1,637,448
2052-2056	823,260	0	823,260	102,092	925,352
Total	$ 7,695,552	$ 100,000	$ 7,795,552	$ 8,247,971	$ 16,043,523

(1) Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds). Years 2017-2018 include projected interest for Long-Term Revolving Credit Agreement.

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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, 2016 are as follows:

Refunding Description		Refunded/Defeased Debt		Outstanding	Original Loss	Unamortized Loss
		(Thousands)			(Thousands)	
Cash Defeasance	$	20,000	1982 Series A	$ 0	$ 2,763	$ 405
2007 Refunding Series B	$	105,370	1997 Refunding Series A	0	8,832	447
2009 Refunding Series A	$	99,515	1997 Refunding Series A			
		20,125	1998 Refunding Series B	0	8,707	3,498
2010 Refunding Series B	$	30,430	2001 Series A			
		118,600	2002 Series B			
		84,780	2002 Refunding Series D	0	22,954	6,421
2011 Refunding Series B	$	8,990	2002 Refunding Series D			
		291,825	2004 Series A	0	23,287	7,357
2011 Refunding Series C	$	134,715	2002 Series B			
		5,160	2007 Series A	0	4,362	3,402
2012 Refunding Series A	$	73,535	2003 Refunding Series A			
		34,160	2004 Series A	0	12,206	6,505
Feb 2012 Defeasance	$	5,615	2003 Refunding Series A	0	749	564
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	0	14,446	12,651
2013 Refunding Series C	$	35,584	2003 Refunding Series A			
		97,695	2008 Series B	0	4,601	3,881

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

Refunding Description		Refunded/Defeased (Thousands)	Debt	Outstanding	Original Loss (Thousands)	Unamortized Loss
2014 Refunding Series C &	$	10,870	2003 Refunding Series A			
Taxable Refunding Series D		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	236,200	32,936	29,584
Nov 2014 Defeasance	$	331,815	2013 Taxable Series D (LIBOR Index)	0	1,097	124
2015 Refunding Series A	$	13,370	2006 Series A			
		32,750	2007 Series A			
		93,035	2008 Series A			
		30,765	2009 Series B	156,550	21,487	17,410
2015 Refunding Series B	$	78,150	2005 Refunding Series C	0	4,987	3,993
2015 Refunding Series C	$	87,560	2005 Refunding Series A			
		217,065	2005 Refunding Series B	0	24,366	17,921
2015 Series E	$	100,000	Barclays Revolving Credit Agreement	0	89	87
2016 Refunding Series A	$	75,885	2007 Series A			
		278,950	2008 Series A			
		20,905	2009 Refunding Series B			
		112,210	2009 Series B			
		75,000	2014 Series A	562,950	56,068	53,494
2016 Refunding Series B	$	97,715	2009 Series E	97,715	12,873	12,605
Total				$ 1,053,415	$ 256,810	$ 180,349

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 2015 current portion of long-term debt showing the amounts paid as debt service in 2016. Also included in the current portion was minibond CAB accretion to be paid in 2016, but collected as debt service during years prior to the maturity date. The remaining amount represents five percent of the original principal for all outstanding minibond issues.

Analysis of December 31, 2015 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from 2016 Revenues	$ 153,221
Minibond CAB accretion debt service paid from Revenues	4,238
Refinanced and Other	
2016 maturities refinanced:	0
5% current portion requirement for original minibond issue amount (1)	15,437
Total	$ 172,896

(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 $149,689 current portion of long-term debt at December 31, 2014 showed that $136,058 was debt service paid from revenues. The remaining $13,631 represented five percent of the original principal for outstanding minibond issues. No maturities included as part of the current portion were refinanced during 2015.

Reconciliations of Interest Charges

Years Ended December 31,	**2016**	2015
	(Thousands)	
Reconciliation of interest cost to interest expense:		
Total interest cost	**$ 366,467**	$ 344,584
Capitalized interest	**(126,385)**	(43,481)
Deferred interest expense	**0**	(18,539)
Interest charged to fuel expense	**(410)**	0
Total interest expense on long-term debt	**$ 239,672**	$ 282,564
Reconciliation of interest cost to interest payments:		
Total interest cost	**$ 366,467**	$ 344,584
Accrued interest-current year	**(54,418)**	(67,378)
Accrued interest-prior year	**67,378**	79,061
Interest released by refundings	**(4,945)**	(6,802)
Accretion on capital appreciation minibonds	**(2,947)**	(3,062)
Total interest payments on long-term debt	**$ 371,535**	$ 346,403

Debt Service Coverage

Years Ended December 31,	**2016**	2015
	(Thousands)	
Operating revenues	**$ 1,745,657**	$ 1,879,553
Interest and investment revenue	**13,001**	9,207
Total revenues and income	**1,758,658**	1,888,760
Operating expenses	**(1,374,942)**	(1,502,488)
Depreciation	**177,004**	176,039
Total expenses	**(1,197,938)**	(1,326,449)
Funds available for debt service prior to distribution to the State	**560,720**	562,311
Distribution to the State	**(19,192)**	(20,116)
Funds available for debt service after distribution to the State	**$ 541,528**	$ 542,195
Debt Service on Accrual Basis:		
Principal on long-term debt	**$ 120,797**	$ 104,555
Interest on long-term debt	**239,672**	282,564
Long-term debt service paid from Revenues	**360,469**	387,119
Commercial paper and other principal and interest	**25,023**	16,146
Total debt service paid from Revenues	**$ 385,492**	$ 403,265
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State	**1.55**	1.45
After distribution to the State	**1.50**	1.40
Including commercial paper and other:		
Prior to distribution to the State	**1.45**	1.39
After distribution to the State	**1.40**	1.34

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 $8.8 billion and $8.5 billion at December 31, 2016 and 2015, respectively.

2016 Bond Market Transactions

Bond market transactions for the year ended December 31, 2016 were as follows:

Revenue Obligations, 2016 Tax-exempt Refunding Series A	**Par Amount:**	**$543,745,000**	**Date Authorized:**	**January 8, 2016**
Summary:	- Issued on February 10, 2016 at an aggregate all-in true interest cost of 3.66 percent - Maturities between December 1, 2021 and December 1, 2048			
Revenue Obligations, 2016 Series M1	**Par Amount:**	**$42,142,700**	**Date Authorized:**	**May 1, 2016**
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 1.65 percent in 2021 and 3.75 percent in 2036			
Revenue Obligations, 2016 Tax-exempt Refunding and Improvement Series B and Taxable Series D	**Par Amount:**	**$831,355,000**	**Date Authorized:**	**June 30, 2016**
Summary:	- Issued on July 20, 2016 at an aggregate all-in true interest cost of 3.53 percent - Maturities between December 1, 2023 and December 1, 2056			
Revenue Obligations, 2016 Tax-exempt Refunding Series C	**Par Amount:**	**$52,400,000**	**Date Authorized:**	**July 22, 2016**
Summary:	- Issued on October 13, 2016 at an aggregate all-in true interest cost of 3.11 percent - Maturities between December 1, 2022 and December 1, 2036			

Debt Covenant Compliance

As of December 31, 2016 and 2015, 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,	**2016**	2015
Outstanding Revenue Obligations	**$7.7 Billion**	$7.1 Billion
Estimated remaining interest payments	**$8.2 Billion**	$8.0 Billion
Issuance years (inclusive)	**2004 through 2016**	2004 through 2015
Maturity years (inclusive)	**2017 through 2056**	2016 through 2055

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, 2016, six 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,		**2016**		2015
Commercial paper outstanding (000's)	**$**	**399,899**	$	$597,520
Effective interest rate (at December 31)		**0.77%**		0.25%
Average annual amount outstanding (000's)	**$**	**547,543**	$	474,479
Average maturity		**38 Days**		37 Days
Average annual effective interest rate		**0.53%**		0.18%

As of December 31, 2016 and 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 for both years. These agreements are used to support the Authority's issuance of commercial paper. There were no borrowings under the agreements during 2016 or 2015.

As of December 31, 2016 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. In August 2016, the Authority secured a $100.0 million loan under the Direct Purchase Revolving Credit Agreement and used these proceeds to pay off $100.0 million of Commercial Paper Notes. This loan remains outstanding at December 31, 2016.

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,		**2016**		2015
		(Millions)		
Plant balances before depreciation	**$**	**545.3**	$	540.3
Accumulated depreciation		**341.7**		334.8
Operation & maintenance expense		**95.6**		86.6

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. This amortization is included in fuel expense and recovered through the Authority's rates.

SCE&G contracted with HOLTEC International, The Shaw Group, Inc. and Westinghouse to build a licensed Independent Spent Fuel Storage Installation (ISFSI), which was completed and commenced receiving fuel in 2016. Because of Department of Energy's (DOE) 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, 2016, reimbursements received equal 68 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 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 2016 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 $369.6 million in 2016 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 $217.7 million (adjusted to market) at December 31, 2016, along with future deposits into the external decommissioning trust fund, investment earnings and credits from future DOE reimbursements for spent fuel storage, are estimated to provide sufficient funds for the Authority's one-third share of the total decommissioning cost.

Nuclear Units 2 and 3

Technology. Summer Nuclear Units 2 and 3 will consist of two Westinghouse Electric Company, LLC ("Westinghouse") AP 1000 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. The AP 1000 is the first and only reactor in its class of technological development, referred to as "Generation III+" to receive certification from the NRC. The AP 1000 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.

Nuclear Regulatory Commission Approvals. The NRC has approved the AP 1000 standard plant design for Summer Nuclear Units 2 and 3. In addition, the NRC has issued the Combined Construction and Operating Licenses ("COLs") with certain conditions for Summer Nuclear Units 2 and 3. To address these conditions, the Authority and SCE&G submitted an overall implementation plan. SCE&G and the Authority are implementing the plan and expect to complete all requirements prior to fuel load as required by the NRC. The Authority and SCE&G do not anticipate any additional regulatory actions related to the plan, but cannot predict future regulatory requirements and how they may impact construction or operation of the new units.

Ownership of the Summer Nuclear Units 2 and 3. On October 20, 2011, the Authority and SCE&G entered into a Design and Construction Agreement specifying an Authority ownership interest of 45% 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. The Authority and SCE&G also entered into an Operating and Decommissioning Agreement on October 20, 2011 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.

In December 2015, the Authority and SCE&G executed a Purchase and Sale Agreement (the "PSA") whereby SCE&G will purchase from the Authority an additional 5% interest in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Such sale is subject to regulatory approvals including approval of the PSC and the NRC. Under the terms of the agreement, SCE&G will own 60% of the two new nuclear units and the Authority will own 40%. The 5% ownership interest will be acquired in three stages, with 1% to be acquired at the commercial operation date of the first new nuclear unit, an additional 2% to be acquired no later than the first anniversary of such commercial operation date and the final 2% to be acquired no later than the second anniversary of such commercial operation date. The purchase price will be based on a pro-rata share of the Authority's actual cost of the units and reimbursement of its financing costs based on the percentage conveyed as of the date of the conveyance. The total purchase price is estimated to be between $700.0 and $900.0 million. The PSA does not impact the Authority's payment obligation for the full 45% ownership during construction. Under the terms of the PSA, the Authority cannot enter into an agreement to sell an additional portion of its 40% ownership interest until both units have been completed. However, under the PSA, the Authority is free to explore power sale opportunities from the facility.

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 Agreement (the "EPC Agreement"), with a consortium consisting of Westinghouse and Stone & Webster, Inc. (the "Consortium"). Pursuant to the EPC Agreement, the Consortium will supply, construct, test, and start up two 1,117 MW nuclear generating units utilizing Westinghouse's AP 1000 standard plant design. On October 27, 2015, the Authority and SCE&G executed a Limited Agency Agreement that appointed SCE&G to act as the Authority's agent in connection with an amendment to the EPC Agreement (the "October 2015 Amendment"). The October 2015 Amendment, which became effective on December 31, 2015 and is described in more detail below under "Nuclear Units 2 and 3 - *October 2015 Amendment to the EPC Agreement*", included an irrevocable option (the "Fixed Price Option") which SCE&G executed on behalf of the Owners on July 1, 2016, 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% portion being approximately $2.737 billion), subject to adjustment for amounts paid since June 30, 2015. Under the Fixed Price Option, the aggregate delay-related liquidated damages amount are capped at $338.0 million per Unit (the Authority's 45% portion being approximately $152.0 million per Unit), and the completion bonus amounts are $150.0 million per Unit (the Authority's 45% portion being approximately $68.0 million per Unit).

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 guarantees, as well as certain bonuses payable to the Consortium for schedule 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. However, see "*Other Recent Project Developments*" herein for information regarding the recently disclosed negative impact on Toshiba's financial results as a result of the impairment of several billions of U.S. dollars.

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) failure by either SCE&G or the Authority to make payment to the Consortium in accordance with the EPC Agreement requirements, (ii) breach by either SCE&G or the Authority of a material provision of the EPC Agreement, or (iii) insolvency of either SCE&G or the Authority unless the other of SCE&G or the Authority has provided security for payments that would be due from such insolvent entity.

EPC Agreement History. Pursuant to the May 23, 2008 EPC Agreement (the "2008 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 bonuses, and adjustments for cost overruns. A majority of the 2008 EPC Agreement costs are fixed or firm. In addition to the 2008 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. In 2012, the COL was issued and the Authority's Board of Directors approved a budget for construction costs associated with a 45% ownership interest of approximately $5.1 billion including related transmission and initial nuclear fuel cores. In October 2015 the Authority and SCE&G executed an agreement with the Consortium to resolve certain disputed matters and amend the 2008 EPC Agreement. See "Nuclear Units 2 and 3 - *October 2015 Amendment to the EPC Agreement*" for additional details.

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 Chicago Bridge and Iron Company ("CB&I"). Stone & Webster continues 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% 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% 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% 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% 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% 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. See "Nuclear Units 2 and 3 - *Other Recent Project Developments*" for additional details.

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 ("DRB") 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.

The October 2015 Amendment also provided the Owner an irrevocable option ("Fixed Price Option") 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 an agreed upon list of items under review, and 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% portion being approximately $2.737 billion). This total amount to be paid would be reduced for amounts paid since June 30, 2015. On June 30, 2016, the Authority's Board of Directors adopted a resolution authorizing the President and CEO of the Authority to execute a Limited Agency Agreement with SCE&G that appoints SCE&G to act as the Authority's agent in connection with the exercise of the Fixed Price Option. In addition, the Board approved a $1.1 billion increase in the Authority's construction budget for the Project from the $5,148,948,000 approved by the Board on April 5, 2012 to $6,248,948,000. On July 1, 2016, SCE&G executed, on behalf of the Owners, the Fixed Price Option in accordance with the requirements of Section 2 of the October 2015 Amendment. On November 28, 2016, the PSC approved SCE&G's execution of the Fixed Price Option. Under the Fixed Price Option, the aggregate delay-related liquidated damages amount referred to in (iii) above are capped at $338.0 million per Unit (Authority's 45% portion being approximately $152.0 million per Unit), and the completion bonus amounts referred to in (iv) above are set at $150.0 million per Unit (Authority's 45% portion being approximately $68.0 million per Unit).

Finally, as noted above, the October 2015 Amendment provides for the development of a revised construction milestone payment schedule and establishes a DRB process for certain commercial claims and disputes, including any dispute that might arise with respect to the development of the revised construction milestone payment schedule. The October 2015 Amendment provides that if the parties are unable to agree upon the revised construction milestone payment schedule by July 1, 2016, then, unless the parties agree or the process is otherwise delayed, the matter will be referred to the DRB. The parties were unable to reach an agreement by July 1, 2016 and as a result, in accordance with the terms of the October 2015 Amendment, the Owner referred the matter to the DRB on August 1, 2016, and the DRB held a hearing on the dispute. The October 2015 Amendment provides that the DRB shall issue its report on the construction milestone payment schedule within 60 days and that for the 60-day period of DRB review, the Owner will pay the Consortium $100.0 million per month in lieu of all other payments (Authority's 45% portion being $45.0 million per month).

On September 30, 2016, the DRB issued an Order directing the parties to develop a milestone payment schedule subject to certain parameters. The DRB's Order also provided that the Owner shall pay to the Consortium for the months of October and November, 2016, the amounts of $133.0 million and $136.5 million, respectively. The parties were unable to reach agreement and after further hearings, the DRB made its final determination and issued an order on December 2, 2016 establishing the Construction Milestone Payment Schedule ("CMPS"). The Authority began making payments pursuant to the CMPS in December 2016. The DRB order provides that certain subcontractor and other supplier related costs incurred by the Consortium will be reimbursed by the Owners regardless of payment-milestone completion, but that other payments will be made only upon documented achievement of the agreed-upon payment milestones. Such subcontractor and other supplier-related costs comprised $1.6 billion of the $4.3 billion that was subject to the DRB order (Authority's 45% portion being $714.3 million).

Substantial Completion Dates and EPC Project Schedule. As outlined in the table "Summary of Substantial Completion Dates" below, there have been several proposed and approved contractual schedule modifications since 2008.

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 - Rebaselined Schedule - August 2014	December 2018 - June 2019 (+12 to +15 months)	June 2020 (+15 months)
EPC - October 2015 Amendment	August 31, 2019 (+2 to +8 months)	August 31, 2020 (+2 months)

Claims specifically relating to COL delays, design modifications of the shield building and certain pre-fabricated 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 guaranteed 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 continued to experience 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 were not accepted as revised contractual substantial completion dates, and the Consortium continued to experience delays.

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. In early August 2014, SCE&G and the Authority received preliminary schedule information in which the Consortium indicated the substantial completion of Unit 2 was 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.

Subsequent to 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. This figure was presented as a total project cost in 2007 dollars subject to escalation and did 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 worked with Consortium executive management to evaluate this information. Based upon this evaluation, the Consortium indicated that the Unit 2 substantial completion date was expected to occur by June 2019 and that the substantial completion date of Unit 3 may be approximately 12 months later. The dates were not accepted as revised contractual substantial completion dates.

On October 27, 2015 the parties amended the EPC which included revised substantial completion dates for Unit 2 and Unit 3 of August 31, 2019 and 2020, respectively. See "*Other Recent Project Developments*" below for additional information on the estimated substantial completion dates.

Construction. Phase I of the construction commenced May 23, 2008 upon 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. 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 a number of key construction milestones were achieved in 2016 as detailed below:

Summer Nuclear Unit 2	
Set Structural Module CA01 (Steam Generator & Refueling Canal)	July 23, 2015
Placed Turbine Building First Bay Basemat Concrete	September 9, 2015
Placed Turbine-Generator Pedestal Concrete	December 20, 2015
Set Structural Module CA03 (IRWST)	July 20, 2016
Set Structural Module CA02 (IRWST/Pressurizer Wall)	August 5, 2016
Set Reactor Vessel	August 30, 2016
Set Generator Stator	October 25, 2016

Summer Nuclear Unit 3	
Set Structural Module CA04 (Reactor Vessel Cavity)	June 29, 2015
Set Structural Module CA20 Subassemblies 3&4	March 12, 2016
Set Containment Vessel Ring 1	April 13, 2016
Set Structural Module CA05	May 2, 2016
Set Structural Module CA20 Subassemblies 1&2	August 16, 2016
Set Shield Building Horizontal Transition Panels	November 9, 2016
Set Structural Module CA01 (Steam Generator & Refueling Canal)	December 16, 2016

The following table sets forth the current status of the project components.

Project Component	% Complete
Engineering	94
Procurement	83
Construction	30

As of December 31, 2016 the Authority has spent $3.8 billion of the total budgeted new nuclear project cost of $6.2 billion.

Other Recent Project Developments. In late 2015, Toshiba's credit ratings declined to below investment grade following disclosures regarding its operating and financial performance and near-term liquidity, pursuant to the above-described terms of the EPC Contract, the Owners obtained payment and performance bonds from Westinghouse in the form of standby letters of credit totaling $45.0 million (or approximately $20.0 million of the Authority's 45% share). These standby letters of credit expire annually and automatically renew for successive one-year periods until their final expiration date of August 31, 2020, unless the issuer provides a minimum 60-day notice that it will not renew its letter of credit. In the event that Westinghouse is unable to meet its payment and performance obligations under the EPC Contract, it is anticipated that the letters of credit will provide a source of liquidity to assist in an orderly transition and in enabling construction activities to continue. In addition, the EPC Contract provides that upon request of the Owners, the Consortium must escrow certain intellectual property for the benefit of the Owners to enable completion of the Summer Nuclear Units 2 and 3. An escrow agreement and account was established in December 2016 and is currently being populated with pertinent intellectual property and software to enable completion of the units.

Toshiba has encountered continued financial difficulties related to the goodwill associated with the Westinghouse acquisition of Stone & Webster. See Note 16 – Subsequent Events for additional detail.

In addition to the above-described project issues, financial difficulties have been experienced by Mangiarotti S.p.A. ("Mangiarotti"), an Italy based supplier responsible for certain significant components of the project. 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 by mid-2017. Since first becoming aware of these financial difficulties, the Consortium has monitored, and continues to monitor, the potential for disruptions in such equipment fabrication and possible responses.

Nuclear Construction - Risk Factors. The construction of large generating plants such as Summer Nuclear Units 2 and 3 involves significant financial and construction risk. No nuclear plants have been constructed in the United States using advanced designs such as the Westinghouse AP1000 reactor and estimating the costs of construction of any new nuclear plant is inherently uncertain. In addition, delays and cost overruns have been incurred, and may continue to be incurred, as a result of certain related 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) financial wherewithal and performance by engineering, procurement, or construction contractors, (g) increases in the cost of debt, (h) financial viability of Westinghouse and/or Toshiba, and (i) inability or unwillingness of Westinghouse and Toshiba to complete the project.

To mitigate potential risks, 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. NND representatives make frequent visits and work closely with the Consortium to monitor progress and issues (engineering, labor, supplier issues, etc.) associated with the AP 1000 nuclear power units currently under construction in China, as well as the units currently under development at nearby Plant Vogtle in Waynesboro, Georgia. A construction oversight review board ("CORB") was formed in 2016 to provide independent oversight of the construction of Units 2 and 3. The board consists of six industry experts that perform quarterly reviews and make recommendations for improvements on all aspects of the project, including licensing, engineering, procurement, construction and testing.

The terms of the amended EPC agreement also provide additional risk mitigation. The risk of additional costs to the Authority and SCE&G resulting from delays is mitigated by increased delay related liquidated damages and the Fixed Price Option. Finally, the Authority has sufficient generating capacity to manage delays of the units coming online and the ability to pass fuel cost differentials to its customers through its existing rates. The Authority's Board also has autonomous rate making authority and the Authority's largest wholesale power sale contract, accounting for over 50% of its revenues, automatically adjusts for changes in costs, including debt service. In addition, O&M costs associated with Summer Nuclear Units 2 and 3, currently in the Authority's rate forecast, will not be incurred during any delay period, partially offsetting fuel cost differentials.

Finally, the Authority and SCE&G, as co-owners of the project, continue to evaluate various actions which might be taken in the event that Westinghouse and Toshiba are unable or unwilling to complete the project. These include, among other things, completing the work under any of several arrangements with other contractors or, were it to be determined to be reasonable and necessary, halting the project.

Note 8 – Leases

The Authority had no outstanding capital leases as of December 31, 2016 or 2015.

Information related to property under operating lease payments follows:

Years Ended December 31,	**2016**	2015
	(Millions)	
Operating lease payments (1)	**$ 2.1**	$ 2.8

(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)	March 2016

(2) The maximum amount due for coal car leases for 2016 is $100,000.

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 Duke Energy Carolinas, LLC (Duke) to the Upstate Load which is defined below, energy Central receives from the Southeastern Power Administration (SEPA) and negligible amounts generated and 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 2016 and 2015 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 (Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc.) who are directly connected to the transmission system of Duke (the Upstate Load) from a supplier other than the Authority.

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

In 2013 the Central and Authority Boards approved an Amendment to the Central Agreement. As part of this Central agreed to extend their rights to terminate the agreement until December 31, 2058. The Central 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 Central 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 2017 three-year capital budget is as follows:

Years Ending December 31,	2017	2018	2019
		(Millions)	
Summer Nuclear Units 2 and 3 (1)	$ 767.7	$ 773.2	$ 681.7
Summer Nuclear Capitalized Interest	125.5	147.2	153.7
Environmental Compliance (2)	279.7	180.3	122.9
General Improvements to the system	199.9	206.6	215.6
Total capital budget (3)	$ 1,372.8	$ 1,307.3	$ 1,173.9

Budget Assumptions:
(1) Construction cash flows for the 2017-2019 budgets reflect 45 percent ownership with subsequent cash flows being reduced in 2019 in accordance with the projected ownership sale date. Total estimated project cost, including transmission and fuel, for our long-term share of the project is $5.6 billion.
(2) Includes ashpond 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, 2016. 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)	
2017	$ 117,873	$ 117,873
2018	120,990	120,990
2019	59,055	59,055
2020	0	0
2021	0	0
Total	$ 297,918	$ 297,918

(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, 2016:

Contracts with Minimum Fixed Payment Obligations

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	19 Years	$ 49.4

Contracts with Power Receipt and Payment Obligations (1)

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	9 Years	$ 175.3
2	2013	27 Years	610.5
1	2013	17 Years	7.4
1	2016	24 Years (2)	428.4

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

(2) Notification was given to terminate this contract on February 23, 2017.

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 2017 and the total transmission obligations for 2018-2027. 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

	2017	2018-2027
	(Thousands)	
Upstate Load(1)	$ 3,040	$ 1,235
Other Customers	2,913	28,824
Total	$ 5,953	$ 30,059

(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, 2016, these contracts total approximately $357.2 million over the next 21 years.

In 2010, the Authority amended the Rainey Generating Station Long-Term Parts and Long-Term Service Contract with General Electric International, Inc. (GEII). 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" under this agreement. The Authority's estimated remaining commitment on the contract is $16.5 million, including escalation. The Authority's Board has approved recovery of contract expenditures on a straight-line basis over the term of the contract.

The Authority successfully negotiated a Contractual Service Agreement, effective March 2016, that covers all remaining units on the plant site and will include the units for Rainey 1 upon completion of the existing contract. The Contractual Service Agreement provides unplanned maintenance coverage, rotor replacement and auxiliary parts replacement in addition to 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 contract value is approximately $123.4 million, including escalation. The contract term extends through 2027 and covers 12 planned maintenance events on the units. The Authority's estimated remaining commitment on the contract is $114.0 million, including escalation.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation (TRANSCO) to supply gas transportation needs for its Rainey Generating Station. The service agreement is for 80,000 dekatherms per day of firm capacity. Additionally, for a term beginning November 1, 2017 through December 31, 2020, the Authority has firm capacity of an additional 25,000 dekatherms through a delivered natural gas agreement via The Energy Authority.

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 2016. 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 2016, 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, 2016. In addition, there have been no third-party claims regarding environmental damages for 2016 or 2015.

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,	**2016**	2015
	(Thousands)	
Unpaid claims and claim expense at beginning of year	**$ 1,479**	$ 1,321
Incurred claims and claim adjustment expenses:		
Add: Provision for current year events	**2,625**	2,377
Less: Payments for current and prior years	**2,085**	2,219
Total unpaid claims and claim expenses at end of year	**$ 2,019**	$ 1,479

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 $13.4 billion by the Price-Anderson Indemnification Act. This $13.4 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 an excess property insurance policy with European Mutual Association for Nuclear Insurance (EMANI) to cover property damage and outage costs up to $415.0 million resulting from an event of non-nuclear origin. 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 $7.2 million for the primary policy, $3.2 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, 2016.

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 NOx emissions, effective January 1, 2015. The CSAPR rule is not expected to negatively impact Santee Cooper.

The Authority continues to review proposed greenhouse gas regulations and legislation 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 announced a final rule to regulate carbon dioxide emissions from power plants entitled the Clean Power Plan. The final rule was published in the Federal Register on October 23, 2015 and has major revisions that benefit South Carolina by allowing the use of new nuclear units at Summer Nuclear for compliance. 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. On February 9, 2016, the Supreme Court in a 5-4 vote granted an emergency stay of the EPA's Clean Power Plan. 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 continue into the summer-fall of 2018.

Through the maximum achievable control technology (MACT) regulatory process, the EPA has promulgated Utility MACT regulations to reduce the emissions of mercury and other hazardous air pollutants (HAPs) from coal and oil-fired electric utility steam boilers. The final MACT rule, renamed the Mercury and Air Toxics Standard (MATS) became effective April 16, 2015. 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 toxins from coal-fired and oil-fired power plants.

Santee Cooper applied for and received a compliance extension for its Cross and Winyah coal-fired EGUs until April 16, 2016. All Santee Cooper coal units are in compliance with the MATS rule.

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. 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 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 14, 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 and believe compliance costs are not significant.

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. Compliance with the ELG rule is integrated with the CCR rule (discussed further below).

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 the Resource Conservation and Recovery Act (RCRA) regarding appropriate disposal of hazardous 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.

The estimated construction costs for compliance with both the ELG and CCR Rules from 2016 through 2030 is $703.0 million.

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 was closed by June 30, 2016.

The Authority has retired units and ancillary facilities at both the Grainger and Jefferies generating stations. The Authority is in the process of closing ash ponds at both facilities by excavation and beneficial use. Closure plans for both the Grainger and the Jefferies ash ponds have been approved by DHEC and closure through beneficial use is in progress.

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.

For pollution remediation liabilities, the Authority recorded $40,000 for pollution remediation liabilities for the year ended December 31, 2015 and zero for the year ended December 31, 2016. 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 Joint Oversight Committee held two additional information gathering meetings in March 2016. The Authority will continue to assist the committee throughout the oversight process.

On January 10, 2017, a bill (H 3225) was filed in the South Carolina House of Representatives 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.

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.

Century Suit. On January 30, 2017, Century Aluminum filed suit against the Authority alleging causes of action for violations of the Sherman Act, the Clayton Act, the South Carolina Unfair Trade Practices Act and the South Carolina Antitrust Act. The Complaint alleges that the Authority engaged in unlawful conduct to maintain a monopoly and engaged in illegal anticompetitive conduct by tying use of Authority transmission lines to other requirements. The Authority is evaluating these claims and will file appropriate responsive pleadings. The Authority cannot predict the outcome of this lawsuit.

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, (8.66 percent employee cost and 11.41 percent employer cost); however, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 6.41 percent is contributed to the SCRS. As of December 31, 2016, the Authority had 51 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 8.66 percent. The Authority contributed 11.41 percent of the total payroll for SCRS retirement. For 2016, 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,	**2016**	2015	2014
		(Millions)	
From the Authority	**$ 15.6**	$ 14.8	$ 13.9
From employees	**11.8**	11.0	10.2
Authority's covered payroll	**140.1**	136.4	131.5
Authority's contributions as a percentage of covered payroll	**11.1%**	10.9%	10.6%

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, 2016, the Authority reported a liability of $325.0 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, 2016 and determined by an actuarial valuation as of July 1, 2015. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $15.5 million paid to SCRS for the year ended June 30, 2016 relative to the actual contributions of $1,071.0 million from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2016 and 2015 are as follows:

	June 30, 2016	June 30, 2015
Authority's proportion of the net pension liability (%)	**1.45%**	1.44%
Authority's proportion of the net pension liability (millions)	**$325.0**	$286.3
Authority's covered employee payroll (millions)	**$140.1**	$136.4
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	**232%**	210%
Plan fiduciary net position as a percentage of the total pension liability	**56.99%**	59.92%

For the year ended December 31, 2016, the Authority recognized a pension expense of $27.6 million, our proportionate share of the total pension expense. At December 31, 2016, 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	**$ 3,217**	**$ 335**
Changes of assumptions	**0**	**0**
Net difference between projected and actual earnings on pension plan investments	**36,641**	**10,538**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**1,035**	**822**
Authority's contributions subsequent to the measurement date	**8,161**	**0**
Total	**$ 49,054**	**$ 11,695**

The Authority reported $8.2 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, 2017. 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, 2016. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2015, measurement date was 4.116 years for SCRS.

Year Ending December 31:	
	(Thousands)
2017	**$ 7,141**
2018	**5,470**
2019	**10,671**
2020	**5,916**
Total	**$ 29,198**

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 was recognized as a reduction of the net pension liability in the year ended 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 involve 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 as of December 31, 2016:

- **Measurement Date**	**June 30, 2016**
- **Valuation Date**	**July 1, 2015**
- **Expected Return on Investments**	**7.50%**
- **Inflation**	**2.75%**
- **Future Salary Increases**	**3.50% to 12.50% (varies by service)**
- **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%.**

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2015:

- 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 - For the measurement date as of June 30, 2016, 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 fourth quarter 2013. 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 (as prescribed by SC Code Section 9-16-335) 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%	1.9	0.04
Short Duration	3.0%	2.0	0.06
Domestic Fixed Income			
Core Fixed Income	7.0%	2.7	0.19
Mixed Credit	6.0%	3.8	0.23
Global Fixed Income			
Global Fixed Income	3.0%	2.8	0.08
Emerging Markets Debt	6.0%	5.1	0.31
Global Public Equity	31.0%	7.1	2.20
Global Tactical Asset Allocation	10.0%	4.9	0.49
Alternatives			
Hedge Funds (Low Beta)	8.0%	4.3	0.34
Private Debt	7.0%	9.9	0.69
Private Equity	9.0%	9.9	0.89
Real Estate (Broad Market)	5.0%	6.0	0.30
Commodities	3.0%	5.9	0.18
Total Expected Real Return	100.0%		6.00
Inflation for Actuarial Purposes			2.75
Total Expected Nominal Return			8.75

For the measurement date as of June 30, 2015, 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 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 – For the measurement date as of June 30, 2016, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.50% as well as SERP discounts rates of 3.50% for both the pre-2007 and the non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Authority's proportionate share of the net pension liability	$ 403,006	$ 324,956	$ 259,794

For the measurement date as of June 30, 2015, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.50% as well as SERP discounts rates of 3.00% for both the pre-2007 and the non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(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-2007 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. At December 31, 2016, the Authority reported an asset of $1.8 million and a liability of $15.2 million associated with the three plans as well as deferred outflows and inflows as follows:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 1,841	$ 1,832
Changes of assumptions	0	55
Net difference between projected and actual earnings on pension plan investments	625	0
Authority's contributions subsequent to the measurement date	96	0
Total	$ 2,562	$ 1,887

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, 2017. 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, 2016.

Year Ending June 30:	
	(Thousands)
2017	$ 165
2018	165
2019	166
2020	(111)
2021	194
Total	$ 579

At December 31, 2015, the Authority reported a net liability associated with the three plans of $12.7 million as well as deferred outflows and inflows as follows:

	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 was 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, 2016 and 2015, the Authority had a noncurrent pension liability of $2.9 million and $0.8 million, respectively.

In accordance with FASB ASC 715, the Authority has a regulatory liability balance of approximately $20.5 million and $19.6 million for the unfunded portion of pension benefits at December 31, 2016 and 2015, 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, 2016.

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 823 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,		**2016**		2015
		(Thousands)		
Annual required contribution	**$**	**11,908**	$	11,561
Interest on OPEB obligation		**531**		485
Adjustment to ARC		**(481)**		(440)
Annual OPEB cost		**11,958**		11,606
Net estimated employer contributions		**(10,413)**		(10,639)
Increase in net OPEB obligation	**$**	**1,545**	$	967
Net OPEB obligation-beginning of year	**$**	**11,169**	$	10,202
Net OPEB obligation-end of year	**$**	**12,714**	$	11,169

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, 2016 and the preceding two years were as follows:

	Annual OPEB Cost	Employer Amount Contributed	Net OPEB Obligation	Percentage Contributed
Years Ended December 31,		(Thousands)		(%)
2014	$12,112	$11,691	$10,202	96.5
2015	11,606	10,639	11,169	91.7
2016	**11,958**	**10,413**	**12,714**	**87.1**

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, and the preceding years is as follows:

Required Supplementary Information - Schedule of Funding Progress

Actuarial Study Date	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)				(%)
2006	$ 0	$ 137,543	$ 101,362	$ 137,543	0.0	135.7
2008	0	107,113	113,730	107,113	0.0	94.2
2010	11,132	131,076	119,318	119,944	8.5	100.5
2012	27,829	170,040	113,683	142,211	16.4	125.1
2014	**39,364**	**184,355**	**120,204**	**144,991**	**21.4**	**120.6**

Note: As of December 31, 2016, the OPEB trust had assets of $48.9 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, 2016 and 2015 were both approximately $11.1 million.

In accordance with FASB ASC 715, the Authority recorded a regulatory liability of approximately $4.8 million and $3.2 million for the unfunded portion of OPEB costs at December 31, 2016 and 2015, 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, 2016.

Note 13 – Credit Risk and Major Customers

In 2016, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:	**2016**	2015
	(Millions)	
Central	**$ 1,018**	$ 1,070

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, 2016 and 2015 was $2.2 million and $1.7 million, respectively.

Note 14 – Storm Damage

2016
In October 2016, the Authority's system sustained damages from Hurricane Matthew. As a result, many counties in South Carolina were declared federal disaster areas, and a relief plan was enacted. The Authority sustained damages to their generation, transmission and distribution systems. During 2016, the Authority incurred $11.4 million in capital and maintenance costs. A receivable of $9.2 million was recorded at December 31, 2016, in anticipation of federal reimbursement in 2017. Additional costs may be incurred in 2017 that should also qualify for federal reimbursement.

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

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. The Authority incurred $4.8 million in expenses, and accrued a $3.6 million receivable at December 31, 2015, in anticipation of a federal refund. The Authority incurred an additional $2.7 million in capital and maintenance expense during 2016. Federal reimbursements received during 2016 totaled $6.2 million. At December 31, 2016, the Authority recorded an additional receivable of $1.6 million for federal reimbursement of associated damages recorded in 2016. It is not anticipated that there will be additional costs in 2017 relating to the event.

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

New Nuclear Construction. Following several preliminary announcements and related media reports, on February 14, 2017, Toshiba, the parent company of Westinghouse Electric Corporation (WEC) and the guarantor of its financial and performance obligations with respect to the EPC Contract, announced that it preliminarily recorded a multi-billion dollar impairment loss associated with the construction of Summer Units 2 and 3 and the two additional AP1000 units being constructed by WEC for another company in the United States.

On December 27, 2016, Toshiba announced the possibility that the goodwill impairment resulting from acquisition by WEC of 100% of the shares of Stone & Webster in 2015 (which had been estimated to be $87.0 million) would reach a level of several billion U.S. dollars, resulting in a negative impact on Toshiba's financial results. The impaired goodwill resulted from WEC's analysis that the cost to complete the four Westinghouse AP1000 new nuclear plants in the United States would far surpass the original estimates for construction. Toshiba attributed the cost overruns to, among other things, higher labor costs arising from lower than anticipated work efficiency and the inability to improve such work efficiency over time. While the final figures related to goodwill and the related impairment remain subject to adjustment, Toshiba's February 14, 2017 announcement indicated it had preliminarily recorded a loss in excess of $6.0 billion.

Toshiba's credit ratings, already below investment grade following disclosures of accounting and internal control irregularities in 2015, were further reduced in January 2017. Toshiba could continue to experience negative financial repercussions resulting from these developments. Their ability to successfully respond to these developments will continue to impact Toshiba's credit ratings, creditworthiness, financial stability and viability. In response, Toshiba has announced, among other things, its plan to monetize portions of its business to generate cash. It has also indicated that it will not take on future nuclear construction projects and that it will significantly alter its risk management oversight of its nuclear business. To date, the contractor has continued to assert their intention to complete construction of Summer Units 2 and 3 and the other two AP 1000 units under construction in the United States. There can be no assurance that Toshiba's or WEC's actions will be sufficient such that Toshiba's lenders and creditors will continue to provide necessary liquidity. In particular, these losses raise uncertainty with respect to Toshiba's ability to perform under its parental guarantees of WEC to the Authority and SCE&G, and further highlight the risks to the Authority related to the construction schedule and WEC's ability to continue with and or complete the construction of Summer Units 2 and 3. Adverse changes in contracts, contractors and subcontractors, and the project schedule could result. Additionally, contractual disputes and litigation could follow.

In addition to the project risks highlighted in Toshiba's disclosures surrounding the large losses described above, additional risks and uncertainties regarding the project schedule are evident. In February 2017, WEC indicated that the contractual guaranteed substantial completion dates of August 2019 and 2020 for Summer Units 2 and 3, respectively, which were reflected in the most recent October 2015 Amendment, are not likely to be met. Instead, revised substantial completion dates of April 2020 and December 2020 are currently reflected within WEC's revised project schedule. There remains substantial uncertainty as to WEC's ability to meet these dates given its historical inability to meet forecasted productivity and work force efficiency levels.

SCE&G and the Authority, the co-owners of Summer Units 2 and 3, continue to evaluate various actions which might be taken in the event that Toshiba and WEC are unable or unwilling to complete the project. These include, among other things, completing the work under any of several arrangements with other contractors or, were it determined to be reasonable and necessary, halting the project.

On February 24, 2017, Fluor Enterprises, Inc., a contractor of Westinghouse Electric Company, LLC, provided SCE&G and the Authority with what is stated by Fluor to be written notice pursuant to S.C. CODE § 29-5-20, (South Carolina's Mechanics Lien Law) claiming that Fluor is owed $78.77 million from Westinghouse for work Fluor had furnished to the Project.

Legislative Matters. On January 10, 2017, a bill (H 3225) was filed in the South Carolina House of Representatives 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.

Century Suit. On January 30, 2017, Century Aluminum filed suit against the Authority alleging causes of action for violations of the Sherman Act, the Clayton Act, the South Carolina Unfair Trade Practices Act and the South Carolina Antitrust Act. The Complaint alleges that the Authority engaged in unlawful conduct to maintain a monopoly and engaged in illegal anticompetitive conduct by tying use of Authority transmission lines to other requirements. The Authority is evaluating these claims and will file appropriate responsive pleadings. The Authority cannot predict the outcome of this lawsuit.

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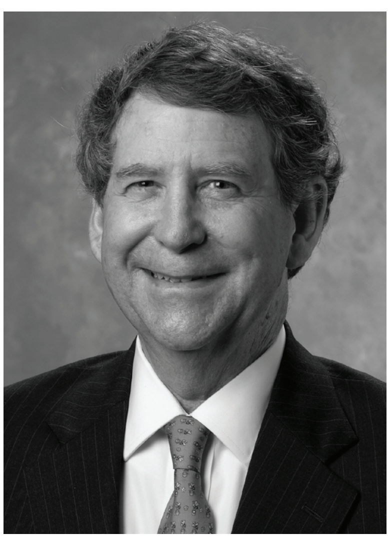
Board of Directors

W. Leighton Lord III
Chairman
At-Large
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.

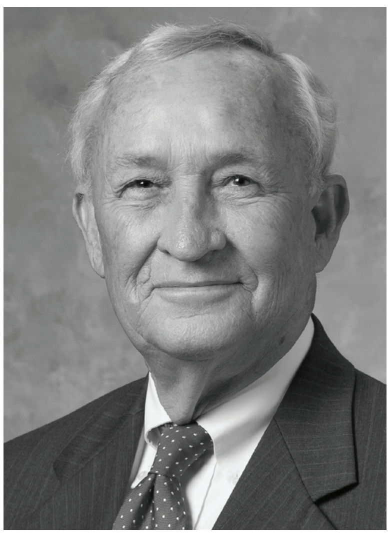


Barry D. Wynn
2nd Vice Chairman
4th Congressional District
Spartanburg, S.C.

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 is a retired staff coordinator for 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.

Stephen H. Mudge
At-Large
Clemson, S.C.

Director Mudge is the co-founder, president and CEO of Serrus Capital Partners Inc., a Greenville, S.C.-based real estate investment firm.

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 president of DR Capital Group, a Pawleys Island-based financial advisory and investment company.

Alfred L. Reid Jr.
5th Congressional District
Rock Hill, S.C.

Director Reid is the director of Lean Manufacturing at 3D Systems in Rock Hill.

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 2, 2016, confirmed Director Stephen H. Mudge to the Santee Cooper Board of Directors and reappointed Director David F. Singleton.

Advisory Board

Nikki R. Haley[1]	*Governor*
Alan Wilson	*Attorney General*
Mark Hammond	*Secretary of State*
Richard Eckstrom	*Comptroller General*
Curtis M. Loftis Jr.	*State Treasurer*

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Marc R. Tye	*Executive Vice President, Competitive Markets and Generation*
Jeffrey D. Armfield	*Senior Vice President and Chief Financial Officer*
J. Michael Baxley	*Senior Vice President and General Counsel*
Michael R. Crosby	*Senior Vice President, Nuclear Energy*
Dominick G. Maddalone[2]	*Senior Vice President, Technology Services and Chief Information Officer*
Arnold R. Singleton	*Senior Vice President, Power Delivery*
Pamela J. Williams	*Senior Vice President, Corporate Services*

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S. Thomas Abrams	*Vice President, Planning and Power Supply*
Charles S. "Sam" Bennett	*Vice President, Administration*
Victoria Budreau[3]	*Vice President, Fuels Strategy and Supply*
Michael C. Brown	*Vice President, Wholesale and Industrial Services*
Thomas B. Curtis	*Vice President, Generating Stations*
Rahul Dembla[4]	*Vice President, Planning and Pricing*
Glenda W. Gillette[5]	*Vice President and Controller*
Jane H. Hood[3]	*Vice President, Environmental and Water Systems*
Thomas L. Kierspe[3]	*Vice President, Transmission Operations*
Richard S. Kizer	*Vice President, Public Affairs*
Kenneth W. Lott III[6]	*Vice President and Treasurer*
J. Michael Poston	*Vice President, Retail Operations*
Suzanne H. Ritter[5]	*Vice President and Controller*
Laura G. Varn	*Vice President, Human Resource Management*
Elizabeth H. Warner	*Vice President, Legal Services and Corporate Secretary*

Auditor

Monique Washington[7]	*Interim General Auditor*

1 - Nikki R. Haley resigned as governor on Jan. 24, 2017, after her confirmation as Ambassador to the United Nations. Henry D. McMaster was sworn in as governor effective Jan. 24, 2017.

2 - Dominick G. Maddalone was hired as Senior Vice President and Chief Information Officer effective June 20, 2016.

3 - Victoria Budreau, Jane H. Hood and Thomas L. Kierspe were named to their current positions effective Nov. 5, 2016.

4 - Rahul Dembla was hired as Vice President, Planning and Pricing effective June 6, 2016.

5 - Suzanne H. Ritter was named Vice President and Controller effective Nov. 5, 2016. The incumbent, Glenda W. Gillette, and Ritter shared job titles during a three-month transition period until Gillette's retirement on Jan. 31, 2017.

6 - Kenneth W. Lott III was named Vice President and Treasurer effective Nov. 5, 2016.

7 - Monique Washington was named Interim General Auditor effective Nov. 5, 2016.

Office Locations

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MONCKS CORNER OFFICE

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1 Riverwood Drive
Moncks Corner, SC 29461
843-761-8000
843-761-4122 – fax

MURRELLS INLET/ GARDEN CITY BEACH 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