santee cooper®

SOUTH CAROLINIANS ***POWERING*** SOUTH CAROLINA

Annual Report 2023

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Letter from the Chairman and CEO

Peter McCoy, *Chairman*

Jimmy Staton, *President and CEO*

Santee Cooper has built a strong legacy as a leading resource in the State of South Carolina in meeting the electricity needs in communities across our state. We energized rural South Carolina beginning in the 1940s and have been serving the people of the state since that time. Today, we are planning for the future so we can continue to serve our customers and communities for years to come.

Santee Cooper's 2023 Integrated Resource Plan (IRP), submitted to the Public Service Commission (PSC) in May 2023 and approved by the PSC in February 2024, was the result of 18 months of detailed analysis and extensive pub- lic input. The preferred portfolio provides a road map for meeting the future power needs of our customers through a modern generation mix that prioritizes flexibility, reliability and affordability. The plan significantly reduces Santee Cooper's carbon footprint by closing coal units, adding flexible natural gas generation jointly built with Dominion Energy South Carolina, and significantly increasing solar power on the system.

This portfolio enables Santee Cooper to continue to power South Carolina reliably – and affordably – in support of South Carolina's growing power-dependent industries across the state.

2023 Accomplishments

Receiving 50-Year FERC License

Santee Cooper achieved a significant milestone on Jan. 20, 2023, when the Federal Energy Regulatory Commission (FERC) issued a new 50-year license order for the continued operation of the Santee Cooper Hydroelectric Project (Lake Marion and Lake Moultrie). This feat is the result of numerous Santee Cooper team members' hard work and dedication and their extensive collaboration with other agencies over the past 20+ years.

The terms and conditions of the license have a focus on threatened and endangered species protection, including increased flows and expanded water quality monitoring in the lower Santee River to protect fish. We are working with a number of other agencies to ascertain achievable solutions that allow us to comply with these important environ- mental requirements.

Meeting Record Growth

Throughout 2023, the number of new customers joining Santee Cooper's system outpaced prior years, with most of that growth occurring along the Grand Strand. When the year ended, Santee Cooper had added 7,832 customers in its retail territory, bringing the total number of residential and business customers to 212,597.

That represents a record year for customer growth at Santee Cooper, and it is a nearly 4% increase over 2022's strong growth of 3%. Myrtle Beach was ranked as the fastest-growing area in the United States for 2023-2024, and so continued growth is likely in 2024.

To help meet that retail growth and similar increases among electric cooperative systems, Santee Cooper purchased the Cherokee County Cogeneration Partners LLC, a roughly 100-megawatt (MW) natural gas combined cycle power plant in Gaffney.

Cherokee offered an existing, in-state solution that matches well with our generating portfolio and will help provide the reliable, affordable power our customers have come to expect. The transaction was supported by Central Electric Power Cooperative and approved by the PSC.

Santee Cooper also signed new purchased power agreements for an additional 250 MWs of power. The new purchased power and Cherokee generating station bring a total 350 MWs to meet short-term capacity needs.

Delivering Outstanding Customer Satisfaction

We saw strong customer satisfaction among residential (96.1% satisfied), commercial (98.7% satisfied), municipal customers (100%) and industrial customers (97.4%). While satisfaction among our cooperative customers has improved, it remains low (57.1% satisfied), and we recognize we need to continue working on those relationships as we move forward.

Supporting Economic Development

Santee Cooper helped our economic development partners secure more than $3 billion in capital investment and approximately 5,000 announced jobs in 2023. Our low rates, incentive loans and grants are powerful tools in helping to secure deals. In addition, Camp Hall Commerce Park, home to Volvo and Redwood Materials, was named 5th best industrial park in the nation, and the only one in the Southeast to be ranked by Business Facilities Magazine.

Focusing on Safety

Safety remains a top priority at Santee Cooper, and the team earned the first-place American Public Power Association's (APPA) Safety Award of Excellence for its focus on safe working practices in 2022 (which was awarded in 2023), reflecting both a low safety-incident rate and Santee Cooper's overall safety program and culture. For 2023, the Recordable Injury rate was 0.77 incidents per 100 people, and the Preventable Motor Vehicle Accident rate was 0.52 incidents per million miles traveled.

Facilitating Electric Innovation

We advanced electric vehicle (EV) infrastructure in our direct-serve territory through our Evolve Grant program. In 2023, Santee Cooper awarded grants to seven exciting new projects submitted by our commercial customers and participated in four ribbon-cutting events showcasing completed EVolve Grant projects with the City of Conway, Coastal Carolina University, McLeod Health and Myrtle Beach Area Chamber of Commerce.

We offer rebates to customers who install qualifying charging stations at their residence, and we have an experi- mental rate program, ChargeSmart, for residential customers who own or lease electric vehicles. ChargeSmart offers time-of-use rates, which encourage customers, through a discounted pricing structure, to shift the electric use for charging their EVs to times of low demand.

Maintaining Excellent Reliability

Santee Cooper again earned APPA's Reliable Public Power Provider Program, or RP3, Diamond-Level Award. The award, which is given every three years, recognizes utilities that demonstrate high proficiency in reliability, safety, workforce development and system improvement. Thanks to the continuing dedication and hard work of our team, Santee Cooper has maintained the RP3 designation since it was first offered in 2006.

In terms of distribution reliability, Santee Cooper again ranked near the top of a national peer group. Data reported to the U.S. Energy Information Administration ranked Santee Cooper 10th (top 2%) among nearly 500 investor- owned utilities and electric cooperatives. The average customer experienced only 22 minutes of outage time in 2023. Our transmission reliability is also very strong at 99.97%, with an average outage time of only 15 minutes.

Growing Water Systems

Santee Cooper's two regional water systems continue to grow and expand to meet area needs. The Lake Moultrie system serves more than 220,000 consumers across the Lowcountry and is growing. The Lake Marion Regional Water System's five-year plan is designed to meet aggressive system growth, with new reaches under construction and five more planned, along with two elevated water tanks and a water plant expansion.

We are also helping the S.C. Department of Health and Environmental Control test treatment technologies for removing PFAS, also known as forever chemicals. Based on our testing, public water systems across the state will be better equipped to choose the best treatment for their plants.

Administering Grid Resiliency Grant

Our Grid Reliability Grant team, working with independent consultant Guidehouse, advanced to the U.S. Depart- ment of Energy for final approval 18 proposals, totaling $10,766,899 in total project costs. The proposals were sub- mitted by electric cooperatives and municipal and other utilities seeking Bipartisan Infrastructure Law funding for federal fiscal years 2022 and 2023 that we are administering on behalf of the State. These proposals offer projects that would strengthen grid reliability against adverse weather events primarily in disadvantaged areas of South Carolina.

Impacting Communities

Santee Cooper's team members are dedicated to making their communities better places to live. In 2023, team members donated more than 25,000 hours of their time in community outreach and volunteerism efforts. They also donated $528,000 to the Trident, Black River (Georgetown), Horry and Anderson United Way organizations.

Santee Cooper organizes and hosts Celebrate The Season, an annual holiday lights driving tour and festival that has raised nearly $1.3 million since 2011 for charity. Supported by dozens of other community business and organization sponsors, the event raised more than $154,000 for area charities during its 2023 season.

Increasing Supplier Diversity

Santee Cooper is proud to partner with suppliers that represent and reflect the citizens and communities of South Carolina, and we believe a diverse and inclusive procurement strategy expands the pool of potential suppliers, enhancing competition and improving the agility of our supply chain. As a result of in-person conversations at supplier fairs and by hosting informational sessions, Santee Cooper increased in 2023 its spend of controllable procurement dollars with minority-, women- or veteran-owned businesses by nearly 5%, compared to 2022.

Improving Credit Ratings

Moody's Investors Service upgraded its outlook on Santee Cooper revenue bonds to stable (from negative) and also affirmed its A3 rating on our debt. Our ratings with Fitch and Standard & Poor's remained at A- with negative outlooks.

Responding to Storms

The Santee Cooper team prepares year-round for the probability of weather – or other emergencies – affecting our system. Hurricane Idalia passed through our system in August, causing minor retail system damage and more signif- icant – but quickly addressed – issues for our transmission system. In total, 2,709 retail customers lost power because of the storm, and we fully restored overnight all customers who could receive power. Five transmission lines locked out over the course of about 12 hours, impacting a total of 17 different cooperative delivery point substations. In each case, the delivery point stations were picked back by transmission switching and sectionalizing, typically within an hour or less.

A December Nor'easter was more damaging for the retail system, causing outages for nearly 31,000 retail customers and minor flooding issues at one of our generating stations. Crews worked overnight to restore service.

Trading Through SEEM

The Southeast Energy Exchange Market (SEEM), of which Santee Cooper is a founding member, observed its one- year operational anniversary in late November and continues to deliver value to Santee Cooper customers. Santee Cooper was very active in that first year, trading more than 110,000 MWh of energy, or roughly 17% of all completed trades across the SEEM footprint. Those transactions have provided approximately $750,000 of fuel cost savings to our system.

Rates

In June, the Santee Cooper Board of Directors approved a comprehensive study of its retail electric rates to address a projected revenue shortfall beginning in 2025. Santee Cooper's current rates were approved in 2015 and last implemented in 2017. A 2020 rate freeze extended those rates through Dec. 31, 2024. The rate study is necessary to ensure we can continue to invest in the reliability of our system as it grows, while also continuing to transition to a greener power mix.

The study is expected to take approximately a year to complete and will include rate adjustments for residential, commercial, industrial, lighting and municipal customers. Any recommendations from that study would require an open and transparent public review and comment period of several months, most likely beginning in summer 2024, prior to any action on new rates.

Santee Cooper remains focused on providing safe, reliable, affordable water and electricity while balancing the cost impact on our customers and maintaining the financial integrity of our state asset.

Award-Winning Utility

In addition to earning APPA's first-place Safety Award for Excellence and the RP3 Diamond-Level Award, Santee Cooper was also recognized in 2023 as:

- An Outstanding Corporate Partner by Trident United Way.
- A Champion of Public Schools by South Carolina School Boards Association.
- A Lower Region Group Leadership Award winner from South Carolina Litter Control Association and Palmetto Pride/Keep South Carolina Beautiful for our partnership with Keep Conway Beautiful.
- A South Carolina Economic Development Impact winner by the Coastal Carolina University Grant Center for Real Estate and Economics.

Conclusion

Santee Cooper powers South Carolina by energizing homes and businesses, hydrating communities with clean, safe water, and helping the state thrive through economic development efforts, strategic partnerships and community support. We are navigating today's challenges and investing in the future, and our team will continue to work each and every day to help improve the quality of life for all South Carolinians.

Peter McCoy
Chairman

Jimmy Staton
President and CEO

CORPORATE STATISTICS

System Data 2023

Miles of transmission system lines[1]:	5,255
Miles of distribution system lines:	3,159
Number of transmission substations:	93
Number of distribution substations:	59
Number of Central Electric Power Cooperative, Inc (CEPCI) Delivery Points (DPs):	427

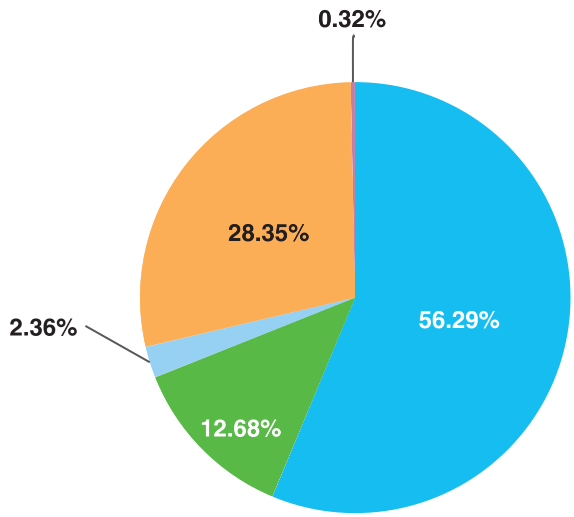
[1] Includes Central-owned transmission lines

	2023	2022	2021	2020	2019 [2]
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,888,400**	$1,974,737	$1,854,350	$1,689,760	$1,613,518
Total Expenses & Interest Charges	**$1,744,573**	$1,960,898	$1,801,232	$1,583,275	$1,676,509
Other	**($8,433)**	($1,026)	$3,146	($54,431)	$48,681
Reinvested Earnings	**$135,394**	$12,813	$56,264	$52,054	($14,310)
OTHER FINANCIAL *(Excluding CP and Other)*					
Debt Service Coverage *(prior to Distribution to State and Special Item, includes Cook Deferred Expenses)*[1]	**1.95**	1.27	1.27	1.46	1.43
Debt / Equity Ratio	**76/24**	77/23	76/24	76/24	76/24
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**212,597**	204,766	198,694	193,930	189,177
Military and Large Industrial	**27**	27	27	27	27
Wholesale - on system	**4**	4	4	4	4
Wholesale - off system	**4**	4	4	4	4
Total Customers	**212,632**	204,801	198,729	193,965	189,212
Generation (MWh):					
Coal	**11,096,020**	9,953,263	10,441,460	8,502,014	9,126,240
Nuclear	**2,499,418**	2,863,279	2,323,542	2,569,684	2,745,960
Hydro	**464,761**	418,764	503,461	756,388	550,468
Natural Gas and Oil	**5,588,689**	5,694,732	5,020,130	5,471,117	5,582,155
Landfill Gas & Renewables	**63,584**	47,651	49,039	47,077	56,012
Total Generation (MWh)	**19,712,472**	18,977,689	18,337,632	17,346,280	18,060,835
Purchases, Net Interchanges, etc. (MWh)	**7,021,907**	7,891,502	6,867,283	5,723,215	5,737,196
Wheeling, Interdepartmental, and Losses	**(549,448)**	(644,818)	(603,873)	(836,321)	(569,323)
Total Energy Sales (MWh)	**26,184,931**	26,224,373	24,601,042	22,233,174	23,228,708
Annual Degree Days	**3,741**	4,250	4,062	3,907	4,316
Summer Generating Capacity (MW)	**5,170**	5,075	5,115	5,110	5,110
Winter Generating Capacity (MW)	**5,388**	5,293	5,343	5,338	5,338
Territorial Peak Demand (MW), Summer	**4,940**	4,746	4,505	4,467	4,507
Territorial Peak Demand (MW), Winter	**4,664**	5,342	4,634	4,456	4,558

[1] See Note 5 - Cook Settlement as to Rates

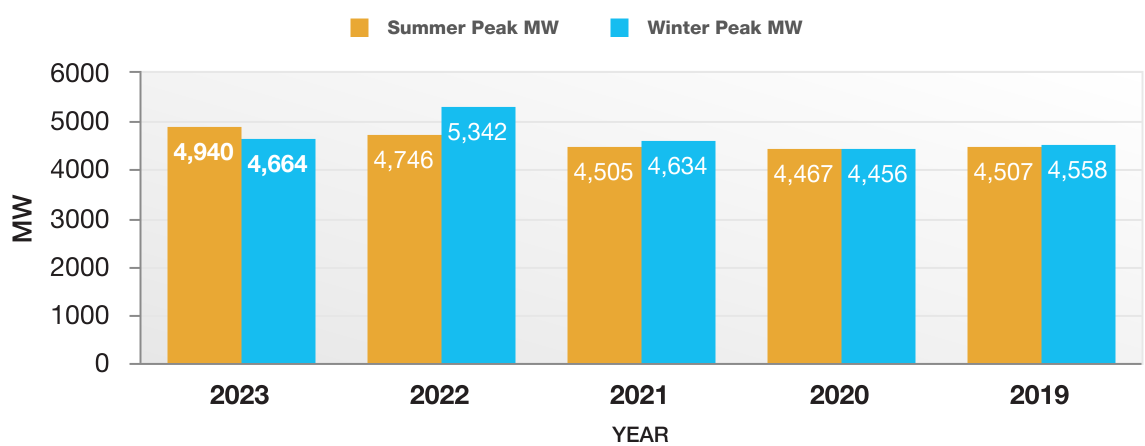
[2] 2019 financial results included a decrease to reinvested earnings from higher net amortization of the Regulatory assets - nuclear over the Deferred inflows - Toshiba settlement. This amortization was to align with impacts from the 2019 debt defeasance as well as capital expenditures.

2023 GENERATION BY FUEL MIX

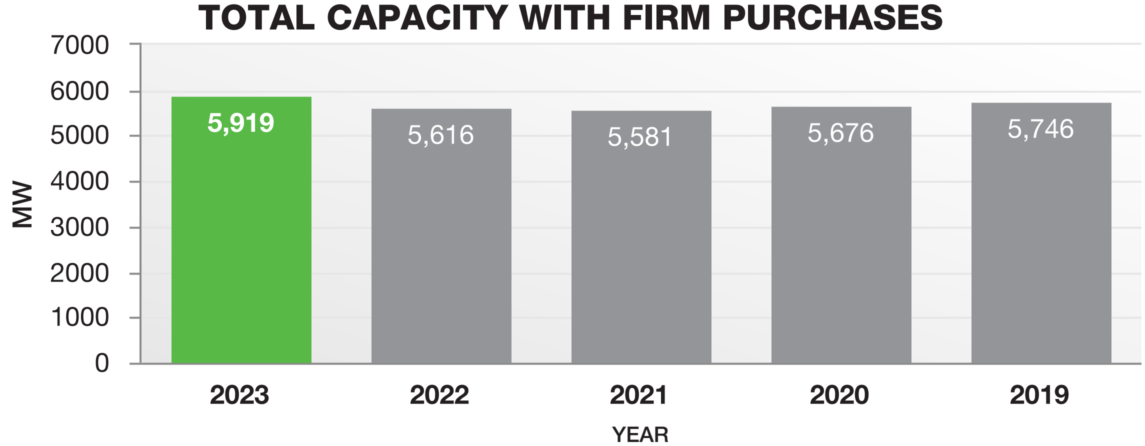


Source		MWh
Coal	56.29%	11,096,020
Nuclear	12.68%	2,499,418
Hydro	2.36%	464,761
Natural Gas and Oil	28.35%	5,588,689
Total Renewables	0.32%	63,584
	100.00%	19,712,472

PEAK DEMAND



TOTAL CAPACITY WITH FIRM PURCHASES



Audit Committee Chairman's Letter

The Audit Committee of the Board of Directors is comprised of independent directors Charles H. Leaird – Chairman, Charles Samuel "Sam" Bennett II, Merrell W. Floyd, Stephen H. Mudge, Stacy K. Taylor, and John S. West.

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 auditors. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent auditors 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.

Charles H. Leaird
Chairman
2023 Audit Committee

Notes:
Charles Samuel "Sam" Bennett II, Stacy K. Taylor, and John S. West were appointed to the committee on June 20, 2023, replacing committee members William A. Finn, Peggy H. Pinnell, and Barry D. Wynn, whose terms on the Board expired.

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Report of Independent Auditors

To the Board of Directors of the South Carolina Public Service Authority

Opinions

We have audited the accompanying financial statements of the business-type activities and fiduciary activities of the South Carolina Public Service Authority ("Santee Cooper"), a component unit of the state of South Carolina, as of and for the year ended December 31, 2023, including the related notes, which collectively comprise Santee Cooper's basic financial statements as listed in the table of contents.

In our opinion, the accompanying financial statements present fairly, in all material respects, the respective financial position of the business-type activities, and fiduciary activities of Santee Cooper as of December 31, 2023, and the respective changes in financial position and, where applicable, cash flows thereof for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinions

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of Santee Cooper and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Other Matter

The financial statements of the business-type activities and fiduciary activities of Santee Cooper as of December 31, 2022 and for the year then ended were audited by other auditors whose report, dated March 15, 2023, expressed unmodified opinions on those statements and included a paragraph describing the limited procedures performed over the required supplementary information presented to supplement the 2022 basic financial statements.

Responsibilities of Management for the Financial Statements

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

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about Santee Cooper's ability to continue

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as a going concern for twelve months beyond the financial statement date, including any currently known information that may raise substantial doubt shortly thereafter.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinions. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS, will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit 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 Santee Cooper's internal control. Accordingly, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about Santee Cooper's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Required Supplemental Information

Accounting principles generally accepted in the United States of America require that the management's discussion and analysis as of and for the year ended December 31, 2023 on pages 16 through 30, schedule of proportionate share of the net pension liability as of June 30, 2023 on page 94, schedule of pension plan contributions for the year ended December 31, 2023 on page 95, schedule of changes in net OPEB liability and related ratios as of and for the year ended June 30, 2023 on page 96, schedule of OPEB contributions for the year ended December 31, 2023 on page 97, and schedule of investment returns for the year ended December 31, 2023 on page 97 be presented to supplement the basic financial statements. Such information is the responsibility of management, and, although not a part of the basic financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the basic financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplemental 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 basic financial statements, and other knowledge we obtained during our audit of the basic financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises the Chairman and CEO Letter, Corporate Statistics, Audit Committee Chairman's Letter, Board of Directors and Leadership, and Office Locations, but does not include the basic financial statements and our auditors' report thereon. Our opinions on the basic financial statements do not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the basic financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the basic financial statements, or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

PricewaterhouseCoopers LLP

Atlanta,
Georgia March
25, 2024

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Management's Discussion and Analysis of Financial Condition and Results of Operations (unaudited)

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. Summer power supply peak capacity totaled 5,170 megawatts (MW) consisting of 3,460 MW of coal-fired capacity, 1,215 MW of natural gas and oil capacity, 322 MW of nuclear capacity, 142 MW of hydro capacity, 26 MW of landfill methane gas capacity and 5 MW of solar capability Winter power supply peak capacity totaled 5,388 MW consisting of 3,480 MW of coal-fired capacity, 1,413 MW of natural gas and oil capacity, 322 MW of nuclear capacity, 142 MW of hydro capacity, 26 MW of landfill methane gas capacity and 5 MW of solar capability.

In addition to its generation assets, 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 Inc. ("Central"), the Authority's largest wholesale customer.

Overview of The Financial Statements

This discussion serves as an introduction to the basic and fiduciary 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 Financial Statements (Note 1 – A -"Reporting Entity"), the financial statements include the accounts of the Lake Moultrie and Lake Marion Regional Water Systems.

The Statements of Net Position – Business – Type Activities 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 Statements of Revenues, Expenses and Changes in Net Position – Business – Type Activities. Revenues represent billings for electricity and wholesale water sales. Expenses primarily include operating costs and debt service-related charges.

The Statements of Cash Flows – Business – Type Activities 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 Statements of Fiduciary Net position – Other Post Employment Benefits (OPEB) Trust Fund summarizes the assets, liabilities, and fiduciary net position of the OPEB Trust Fund.

The Statements of Changes in Fiduciary Net Position – OPEB Trust Fund reports additions to and deductions from the OPEB Trust Fund.

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

Financial Condition Overview

The Authority's Statements of Net Position as of December 31, 2023, 2022 and 2021 are summarized below

	2023	2022	2021
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 5,095,612**	$ 5,008,163	$ 5,108,947
Current assets	**1,304,252**	1,568,740	1,294,801
Other noncurrent assets	**4,917,531**	4,788,349	4,436,986
Deferred outflows of resources	**829,286**	976,711	872,566
Total assets & deferred outflows of resources	**$ 12,146,681**	$ 12,341,963	$ 11,713,300
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 7,605,551**	$ 7,573,550	$ 6,961,591
Current liabilities	**595,916**	672,284	671,887
Other noncurrent liabilities	**1,124,911**	1,239,117	1,240,899
Deferred inflows of resources	**569,951**	723,093	700,143
Total liabilities & deferred inflows of resources	**$ 9,896,329**	$ 10,208,044	$ 9,574,520
NET POSITION			
Net invested in capital assets	**$ 2,001,334**	$ 2,040,738	$ 2,116,131
Restricted for debt service	**12,182**	20,698	9,214
Unrestricted	**236,836**	72,483	13,435
Total net position	**$ 2,250,352**	$ 2,133,919	$ 2,138,780
Total liabilities, deferred inflows of resources & net position	**$ 12,146,681**	$ 12,341,963	$ 11,713,300

2023 Compared to 2022

The primary changes in the Authority's financial condition as of December 31, 2023 and 2022 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources decreased $195.3 million during 2023 due to decreases of $264.5 million in current assets, and $147.4 million in deferred outflows of resources. These decreases were offset by increases of $87.4 million in capital assets and $129.2 million in other noncurrent assets.

The increase in capital assets of $87.4 million was due to an increase during 2023 in capital construction spending which included solid waste, landfill and Effluent Limitation Guidelines (ELGs) system along with the Marion-Conway 230kV line and various large distribution and generation additions. This was offset by a smaller increase in accumulated depreciation.

The decrease in current assets of $264.5 million was primarily due to decreases in unrestricted and restricted cash and investments of $260.0 million. The net decreases were caused mainly from higher debt service payments offset by higher net operating receipts in the current year along with higher net investment income (including fair market value adjustments). Fuel stocks increased $78.4 million attributed to an increase in fossil fuel physical quantities and higher fuel prices. Accounts receivables decreased $45.2 million, primarily caused by decreases in the Central Electric Power Cooperative, The Energy Authority, and industrial receivables resulting from lower volumes and lower fuel rate revenues. Prepaid expenses & other current assets decreased by $52.9 million due mainly to a decrease in the current derivative assets (including fair market value adjustments). Materials and supplies inventory increased $14.6 million due to higher

market prices of commodities as well as inventory items added with the purchase of the Cherokee generation facility during late 2023.
Interest receivable increased $1.2 million due mainly to higher investment income. Additionally, there was a small net decrease of $600,000 in the smaller other remaining current assets.

The increase in other noncurrent assets of $129.2 million resulted mainly from the recording of additional Cook Settlement Exceptions regulatory asset adjustments of $266.5 million during 2023. This was partially offset by the decreases in noncurrent assets due to an investment loss (including market value adjustments) and a decrease in the noncurrent regulatory asset – nuclear due to transfers to current. Other noncurrent assets netted to small variances between the years.

Deferred outflows of resources decreased $147.4 million, due mainly to the decreases in these line items. Decreases in deferred outflow - pension of $45.8 million resulting from the 2023 actuarial study driven by the investment experience, unamortized loss on refunded and defeased debt of $12.3 million resulting from normal amortization during 2023, the accumulated fair value of hedging derivatives also decreased by $6.3 million due to lower deferred losses compared to the prior period, and a decrease in deferred outflow - ARO of $81.5 million due to continued ash pond removals and an adjustment to align our one third nuclear related asset retirement obligations with the majority owner's decommissioning study. In addition, the deferred outflow – OPEB decreased $1.5 million, resulting from the 2023 actuarial study driven by a change in assumptions.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources decreased $311.7 million. This was due to a decrease of $76.4 million in current liabilities, a decrease in other noncurrent liabilities of $114.2 million, and a decrease of $153.1 million in deferred inflows of resources. These decreases were partially offset by an increase of $32.0 million in long-term debt.

Long-term debt - net increased $32.0 million. This resulted primarily from Long Term Revolving Credit Agreements which increased by $185.0 million due to current period draws partially offset by $2.0 million from paydowns and transfers to short term. This was further offset by a $62.7 million debt cash defeasance in December 2023 and $56.6 million in transfers to current portion. Also there was a $30.7 million decrease in unamortized premiums and discounts and a $1.0 million reduction from removals resulting from the December cash defeasance.

The decrease in current liabilities of $76.4 million was due mainly to decreases in other current liabilities of $132.5 million and a decrease of $25.8 million in accounts payable. These decreases were partially offset by increases of $65.1 million in commercial paper and $17.1 million in the current portion of long-term debt. The other current liabilities decrease was primarily a result of a lower deferred liability offset of $126.0 million in hedging collateral received due to lower forward commodity prices, and a $5.9 million decrease in the current mark to market loss liability account along with smaller net decreases of approximately $600,000 in the remaining categories. The accounts payable decrease resulted from lower purchased power liabilities offset by a higher nuclear fuel liability along with higher V. C. Summer nuclear related accounts payables. The increase in commercial paper liabilities was due to an increase of $131.6 million resulting from new issuances offset by $66.5 million due to paydowns. Current portion - long term debt increased due mainly to net higher current year transfers into current portion offset by lower principal payments under debt service requirements. In addition, there was a small net decrease of $300,000 between accrued interest on long term debt and the revolving credit agreement liabilities.

The decrease in other noncurrent liabilities of $114.2 million resulted primarily from reductions in the net pension and net OPEB liabilities of $53.8 million and $6.1 million, respectively. This resulted from the 2023 actuarial study updates with changes in investment return and discount assumptions for the current year. Also a $71.7 million reduction in the asset retirement obligations because of continued ash pond removals and an adjustment to align our one third nuclear related asset retirement obligations with the majority owner's decommissioning study in 2023. This was offset by increases totaling $16.7 million in other credits and noncurrent liabilities for nuclear associated net pension and OPEB resulting from the 2023 actuarial study updates, landfill closure updates, and the change in the deferred liability for Camp Hall sales for 2023. Other items in this line item accounted for small net increases of approximately $700,000 between the years being compared.

Deferred inflows of resources decreased $153.1 million largely due to a lower accumulated value in fair value of hedging derivatives of $152.6 million caused by lower mark to market gains associated with lower natural gas prices reducing future settle prices. There were also decreases of $49.6 million in deferred inflows - pension associated with changes in assumptions for investment experience in the 2023 actuarial study and deferred inflows - Toshiba settlement due to amortization of $8.9 million. These decreases were partially offset by increases in deferred inflows – OPEB of $45.4 million due changes in assumptions to the 2023 actuarial study and deferred inflows - nuclear decommissioning costs of $12.6 million, mainly to higher market values and changes in projected earnings rates and NRC required minimum funding.

The increase in net position of $116.4 million was due to positive operating results. Unrestricted net position increased $164.3 million, offset by lower net investment in capital assets of $39.4 million and lower restricted net position of $8.5 million.

2022 Compared to 2021

The primary changes in the Authority's financial condition as of December 31, 2022 and 2021 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $628.7 million during 2022 due to increases of $274.0 million in current assets, $351.4 million in other noncurrent assets, and $104.1 million in deferred outflows of resources. These increases were offset by smaller decreases of $100.8 million in capital assets.

The decrease in capital assets of $100.8 million was due to higher accumulated depreciation, offset by capital asset additions. Capital spending was reduced in 2022, resulting in lower capital asset additions. Projects going into service included: new absorber tanks and vessels at Cross Unit 1; Cross Units 3 and 4 reheater work; Cross 1 boiler work and finishing superheater assembly; and the Carnes Crossroads transformer addition.

The increase in current assets of $274.0 million was primarily due to increases in unrestricted and restricted cash and investments of $153.5 million. The net increases came mainly from proceeds received from the 2022 E tax exempt bond proceeds less debt service payments, funding the current year cash defeasances, fund transfers and capital expenditures. Fuel stocks increased $46.1 million due to higher priced fuel and fuel management practices. Accounts receivables increased $44.6 million, primarily caused by increases in the Central Electric Cooperative and The Energy Authority receivables. Also, prepaid expenses & other current assets increased by $38.5 million due mainly to an increase in the current derivative assets. Materials and supplies inventory increased $18.8 million due to higher market prices of commodities. Regulatory assets - nuclear decreased by $28.6 million ~~is~~ due to reduced amortization scheduled for 2023, resulting in less transfers from noncurrent regulatory assets – nuclear. Other smaller accounts netted to approximately an increase of $1.1 million in this category.

The increase in other noncurrent assets of $351.4 million resulted from the recording of the Cook Settlement Exceptions regulatory asset of $358.6 million during 2022. This was partially offset by the decreases in noncurrent restricted investments due to an investment loss (including market value adjustments) and a decrease in the noncurrent regulatory asset – nuclear due to transfers to current. Other noncurrent assets netted to small variances between the years.

Deferred outflows of resources increased $104.1 million, due mainly to the increase in Unamortized loss on refunded and defeased debt of $124.4 million resulting from loss additions related to the 2022 AB Refunding bond issue. The accumulated fair value of hedging derivatives also increased by $14.4 million due to higher deferred losses compared to the prior period. The deferred outflow – OPEB increased $16.4 million, resulting from the 2022 actuarial studies driven by the investment experience. These increases were partially offset from a decrease in the deferred outflow – ARO of $34.1 million due to continued ash pond removals.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $633.5 million due to increases of $612.0 million in long-term debt, $0.4 million, in current liabilities, and $22.9 million in deferred inflows of resources. These increases were partially offset by a decrease of $1.8 million in other noncurrent liabilities.

Long-term debt - net increased $612.0 million. This resulted from the net debt increases of $311.7 million related to the 2022 AB Refunding bond issue, 2022 CDEF Refunding and Improvement bond issues, removals of the bonds being refunded along with the March and December cash defeasances. Long Term Revolving Credit Agreements increased by $200.5 million due to current period draws. Unamortized debt discounts and premiums also increased by $99.8 million due mainly to the impact of the associated 2022 net bond activity.

Total current liabilities were relatively consistent with prior years, key changes in individual components were as follows: increases in other current liabilities of $45.0 million and an increase of $27.3 million in accounts payable. These increases were partially offset by a decrease of $68.3 million in the current portion of long-term debt. The other current liabilities increase was primarily a result of a higher deferred liability offset of $75.8 million in hedging collateral received, partially offset by a $70.0 million decrease in the Cook Settlement Agreement liability. The accounts payable increase resulted from higher purchased power liabilities partially offset by lower Summer nuclear accounts payables. Current portion - long term debt decreased due mainly to lower principal payments under debt service requirements.

The decrease in other noncurrent liabilities of $1.8 million resulted mainly from a reduction of $38.9 million in the asset retirement obligation because of continued ash pond removals in 2022. This was offset by increases in the net pension of $14.1 million and net OPEB liabilities of $14.5 million, resulting from the 2022 actuarial study updates with lower investment assumptions for the current year. Further offsetting the decrease was an increase of $8.5 million in the deferred liability account for Camp Hall sales.

Deferred inflows of resources increased $22.9 million largely due to higher accumulated increase in fair value of hedging derivatives of $89.2 million, resulting from higher mark to market gains associated with higher natural gas prices increasing future settle prices. This was partially offset by decreases in deferred inflows – nuclear decommissioning costs of $41.4 million, mainly from lower market values and reduced funding due to changes in projected earnings rates and NRC required minimum funding; deferred inflows - pension of $13.7 million associated with changes in assumptions and better investment performance in the 2022 actuarial study; and deferred inflows - Toshiba settlement amortization of $9.1 million. Further offsets were provided by deferred inflow - OPEB of $2.1 million from changes in the 2022 actuarial study.

The decrease in net position of $4.9 million was due to negative operating results. Net invested in capital assets decreased $75.4 million. This was offset by unrestricted net position of $59.0 million and restricted for debt service of $11.5 million.

Results of Operations

Santee Cooper's Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2023, 2022 and 2021 are summarized as follows:

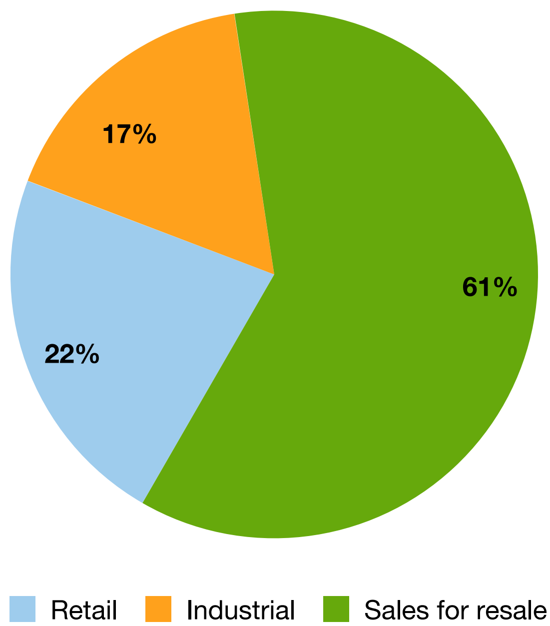
	2023	2022	2021
		(Thousands)	
Operating revenues	**$ 1,850,603**	$ 1,949,050	$ 1,765,785
Operating expenses	**1,429,528**	1,670,010	1,496,286
Operating income	**421,075**	279,040	269,499
Interest expense	**(315,045)**	(290,888)	(304,946)
Costs to be recovered from future revenue	**(8,433)**	(1,026)	3,145
Other income	**37,797**	25,688	88,566
Capital contributions, transfers and special item	**(18,961)**	(17,675)	(17,135)
Change in net position	**$ 116,433**	$ (4,861)	$ 39,129
Net position - beginning of period	**$ 2,133,919**	$ 2,138,780	$ 2,099,651
Ending net position	**$ 2,250,352**	$ 2,133,919	$ 2,138,780

2023 Compared to 2022

Operating Revenues

Comparing 2023 to 2022, operating revenues decreased $98.4 million (5%), primarily driven from lower fuel rate revenues of $52.5 million, due to an overall decrease in commodity prices year over year. Contributing to the decrease were lower energy revenues of $30.8 million from unfrozen Economy Power fuel rates due to lower fuel costs in the current year. Other factors causing the decrease included lower: (i) off system sales of $10.6 million; (ii) demand rate revenues of $2.6 million; and (iii) other smaller revenue adjustment decreases of $1.9 million between the two periods. Milder weather caused most of the impact lowering heating degree days 12% in the current year. For comparison, energy sales for 2023 and 2022 were virtually the same totaling approximately 26.2 million megawatt hours (MWhs).

2023 Revenues from Sales of Electricity*
by Customer Class



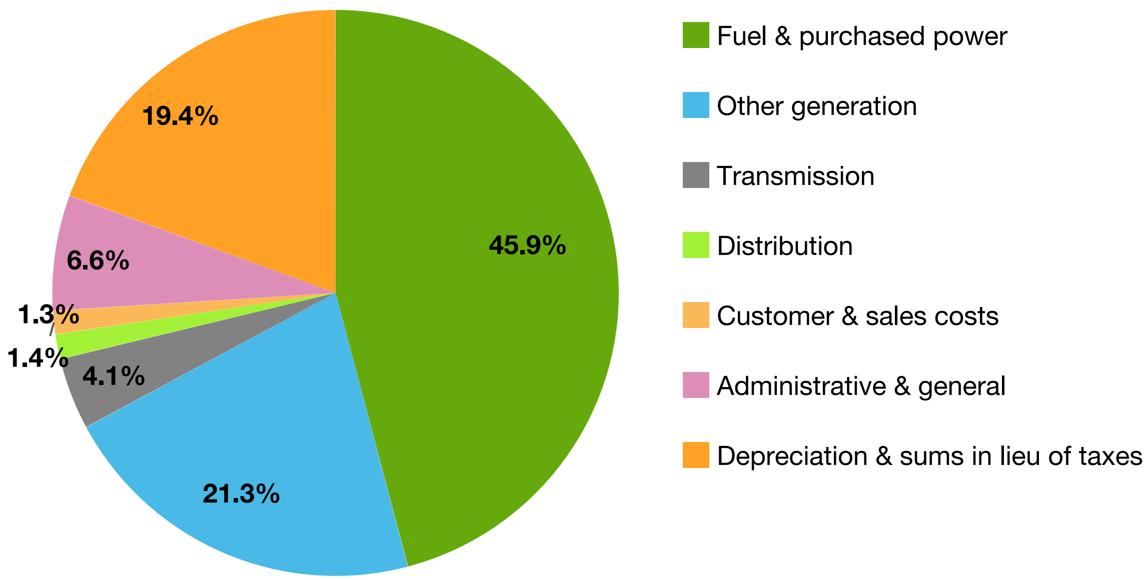
	2023	2022	2021
Revenues from Sales of Electricity*		(Thousands)	
Retail	**$ 409,762**	$ 405,973	$ 406,969
Industrial	**306,602**	386,211	274,202
Sales for resale	**1,108,760**	1,131,579	1,059,588
Totals	**$ 1,825,124**	$ 1,923,763	$ 1,740,759

*Excludes interdepartmental sales of $592 for 2023, $615 for 2022 and $582 for 2021.

OPERATING EXPENSES

Operating expenses for 2023 decreased $241.7 million (15%) as compared to 2022. The major causes were lower fuel and purchased power expenses which decreased $428.1 million due to lower prices in the current year purchased power and natural gas markets. This was offset somewhat by lower Cook settlement exception regulatory asset credits of $89.7 million as compared to the prior year due to the lower current year purchased power and natural gas prices experienced in 2023. Additional offsets to the decrease were: (i) higher non-fuel generation expense which showed an increase of $72.9 million from higher contract services and materials from larger scopes on Winyah, Cross, and Rainey outages, increased Winyah and Cross maintenance costs, increased gypsum purchases, and higher nuclear expenses from higher Dominion corporate cost allocations and operational expenses; (ii) transmission increased $12.8 million from higher outside transmission costs, labor, materials, and contract services; and (iii) administrative and general expense were higher $9.7 million mainly caused by labor associated with higher pension expense in 2023 compared to 2022. Other smaller changes netted to the remaining variance.

2023 Electric Operating Expenses by Category



	2023	2022	2021
Electric Operating Expenses		(Thousands)	
Fuel & purchased power	**$ 652,622**	$ 991,017	$ 770,115
Other generation	**302,186**	229,251	288,840
Transmission	**58,568**	45,679	42,338
Distribution	**20,076**	21,515	17,997
Customer & sales costs	**18,997**	19,528	17,903
Administrative & general	**93,758**	84,099	90,844
Depreciation & sums in lieu of taxes	**275,925**	272,747	262,134
Totals	**$ 1,422,132**	$ 1,663,836	$ 1,490,171

Non-Operating Income (Expense)

Regulatory amortization and other income provided a combined increase to non-operating expense of $11.5 million, in 2023 as compared to 2022. This resulted primarily from lower amortization of the nuclear regulatory asset of $23.1 million due, resulting from lower principal payments on nuclear debt coming due in the current year. Another contributing item to the increase was a change in the fair value of investments of $19.0 million and higher interest income of $9.9 million. Offsetting these increases were lower nuclear equipment and Camp Hall sales of $38.3 million and lower smaller items in this category netting approximately $2.2 million.

Interest charges increased $24.3 million, resulting primarily from the impact of the 2022 E & F bond issue in November 2022. This increase was net of higher credits to interest expense from borrowings related to the Cook settlement exception regulatory asset in the current year.

CTBR expense was higher year over year by $7.6 million because of higher principal amortization in the current year.

Transfers represent dollars paid to the State.

2022 Compared to 2021

Operating Revenues

Compared to 2021, operating revenues increased $183.3 million (10%), primarily from higher fuel rate revenues of $77.0 million, mainly in the Industrial category. Higher energy sales (7%), demand usage (8%) and demand rate revenues also increased revenues by $40.7 million, $31.1 million and $18.7 million, respectively. Degree day increases of 5% contributed to increased revenues in our retail and wholesale businesses. Further contributions were made by higher off system Municipal sales of $14.7 million. Also contributing was the change between the periods for the Central Cost of Service adjustments of $15.2 million. The 2021 adjustments were higher due to the finalization of 2020's adjust-to-actual and accruals for 2016, 2017 and 2018's audit issues of $21.6 million. In addition, the 2021 adjust-to-actual accrual was $2.4 million higher as compared to 2022. The 2022 adjustments included accruals for 2018 & 2019 audit issues of $8.0 million. Somewhat offsetting these increases were lower O&M rate revenues of $12.3 million. Energy sales for 2022 totaled approximately 26.2 million megawatt hours (MWhs), as compared to approximately 24.6 million MWhs for 2021.

Operating Expenses

Operating expenses for 2022 increased $173.7 million (12%) as compared to 2021 fuel and purchased power credits of $327.1 million from the Cook Settlement Exceptions regulatory asset. Primary drivers were higher: (i) fuel and purchased power expense of $548.0 million from higher kWh sales, higher commodity prices for the generation mix utilized and increased use of higher cost purchased power due to coal stockpile management, as well as higher costs in the energy markets due to elevated natural gas prices; (ii) depreciation of $10.6 million from assets placed into service in the current year; (iii) distribution of $3.5 million from higher labor and contract services in the current year; and (iv) transmission of $3.3 million from higher transmission purchases associated with purchased power. Further offsetting these increases were lower: (i) non-fuel generation of $59.6 million mainly from lower contract services and materials due largely to smaller Cross, Winyah and Rainey maintenance outage scopes. V.C. Summer expenses were lower due to higher software integration expense in the prior year; and (ii) administrative & general of $6.7 million from contract services due to lower legal expense. Non-fuel generation and administrative & general are shown net of credits from the Cook Settlement Exceptions regulatory asset of $16.7 million and $5.4 million, respectively.

Non-Operating Income (Expense)

Regulatory amortization and other income provided a combined increase to non-operating expense of $63.0 million, in 2022 as compared to 2021, resulting primarily from lower amortization of the Toshiba regulatory liability of $36.2 million, higher amortization of the nuclear regulatory asset of $49.0 million associated with the cash defeasance of nuclear bonds in December of 2022 and lower TEA income of $11.7 million in the current year. This was offset by higher Summer Nuclear 2 & 3 sales of $23.3 million, interest income of $4.5 million, an increase in the fair value of investments of $2.8 million and the Hearn settlement expense in the prior year of $2.8 million.

Interest charges decreased $14.0 million, resulting mainly from the 2021 A Refunding in late 2021 and the 2022 AB Refunding in February 2022, as well as the Cook Settlement Exceptions regulatory asset which lowered interest charges by $8.4 million.

CTBR expense was higher year over year by $4.2 million as a result of higher principal amortization in the current year. The change of water CTBR was $361,000 between the years as a result of debt paydowns.

Transfers represent dollars paid to the State.

Economic Development

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 economic development programs that revolve around four strategic initiatives:

(1) Marketing – includes market commercial and industrial properties, providing grants to economic development allies for marketing purposes, and providing closing fund grants to help close projects; (2) Product Development – the Authority's Economic Development Loan Program provides funding for product development (land acquisition, building construction, and infrastructure); (3) Project management – in-house expertise can be utilized for certain engineering, environmental, and property and/or site consultation; and (4) Competitive rates.

Since June 2012, the Authority has invested nearly $146 million throughout South Carolina in product development activities through low interest revolving loans and grants to public entities.The Authority's commitment to economic development efforts with the State, the electric cooperatives and other economic development partners also brought additional announcements of business growth projects during 2023, including Metglas, Inc. in Horry County, ZEB Materials in Berkeley County, and Latitude Corporation in Clarendon County.

The Authority's largest customer, Central Electric Power Cooperative, Inc ("Central"), accounted for 58 percent of operating revenues in 2023. Central provides wholesale electric service to each of the 19 distribution cooperatives which are members of Central pursuant to long-term all requirements power supply agreements that extend through December 31, 2058.

In May 2013, the Authority and Central approved an amendment to their contract (the "Coordination Agreement") and agreed to extend their termination rights. Under the Coordination 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's power supply agreements with their member cooperatives obligates those members to pay their share of Central's costs, including costs paid under the Coordination Agreement. The Authority and Central have also resolved certain matters relating to the nuclear project through the execution of the Cook Settlement Agreement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement.

Fuel cost in 2023 were down from the historic levels experienced in 2022. The Authority's load requirements were normal throughout the year, with no major weather events. The Authority's coal inventory, although priced higher than in previous years due to factors related to the Sugar Camp mine fire of 2021, remained above the Authority's operational target range (800 thousand to 1.2 million tons) throughout most of the year. Purchased energy market prices were lower than expected and the Authority was able to participate in that market by reducing the Authority's own generation resources; however, when there were price spikes, the Authority was able to switch back to the Authority's coal resources.

The Authority's 2023 system rate of $31.65/MWh was lower than the Authority's 2022 system rate and the Authority's 2023 Budget projections. 2023 system rate is also in line with historical average system rates even though we have seen inflationary pressures throughout the past decade.

Legislative Matters

The 2023-2024 SC legislative session began January 10, 2023, and the second year of that two-year session began on January 9, 2024. The two-year session is scheduled to adjourn on May 9, 2024.

The SC Governor and legislative leaders have identified a need in South Carolina for new dispatchable, reliable, and affordable energy. The Governor has initiated a state action group name 'PowerSC' to address energy challenges for South Carolina and develop an energy plan. Legislative leaders, including the SC Speaker of the House, are pursuing an agenda to improve energy capacity for South Carolina as well.

It is expected that energy policies, including policies that will enable and support the Authority's resource plan, will be discussed and addressed in the 2024 legislative session. In addition, the South Carolina Public Service Commission approved the Authority's 2023 Integrated Resource Plan on February 15, 2024.

Increased Focus On Sustainability

The Authority has increased its focus on sustainability with the creation of a standalone department that has been tasked with developing and implementing an enterprise-wide strategic plan for sustainability as well as leading the Authority's just transition efforts with impacted stakeholders related to its planned retirement of the Winyah Generating Station. The creation of its new sustainability department is a part of the Authority's continued commitment to sustainable business practices and corporate responsibility.

The Authority's increased emphasis on sustainability goes hand in hand with its corporate mission to improve the quality of life for all South Carolinians. Its sustainability efforts are guided by overarching corporate strategic goals for 2023 centered on four key areas. **People –** with the objective of shaping and cultivating a corporate culture in which employees feel safe, included, and engaged. **Perception –** with the objective of exceeding the expectations of customers and stakeholders through innovation, transparency, and service. **Performance –** with the objective of modernizing Santee Cooper through several initiatives, including among other things fuel diversification and investment in emerging technology. And finally, **Profitability –** with the objective of delivering and executing on a financial plan that addresses dynamic internal and external market forces.

The Authority has made great strides in each of these areas from the continued good work of its IDEA (Inclusion, Diversity, Equity, and Awareness) Council, to the over 25,000 hours of outreach in the communities it serves provided by the Authority's employees. Additionally, for the second year in a row the Authority finished the year with a top ten finish in reliability out of nearly 500 utilities, not to mention its role as the administrator on behalf of the State of South Carolina for over $10.4 million in grant funds awarded by the U.S. Department of Energy for strengthening the state's electric grid resiliency.

The Authority continues its commitment to and focus on sustainable practices that prioritize long-term economic performance, environmental stewardship, reliable, affordable energy and water, effective corporate governance, corporate responsibility, and transparency. As a part of its commitment, the Authority has increased its disclosure around sustainability and additional information about its efforts are included in its 2023 Sustainability Report which will be available on April 30, 2024, on the Authority's website at https://www.santeecooper.com/about/.

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 Chemical Facility Anti-Terrorism Standards ("CFATS") program identifies and regulates high-risk chemicals facilities to ensure they have security measures in place to reduce the risk associated with these 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 CFATS program, also referred to as 6 CFR, Part 27. Once completed, the assessments become sensitive, federally controlled documents and are stored in accordance with all federal and state guidelines attendant to critical infrastructure information protection.

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 2023, 2022 and 2021 was as follows:

Approved in:	2023 Budget 2024-26	2022 Budget 2023-25	2021 Budget 2022-24
Capital Improvement Expenditures		(Thousands)	
Environmental Compliance [1]	**395,157**	$ 286,757	$ 241,824
General Improvements and Other [2]	**1,501,622**	818,716	723,266
Load and Resource Plan [3]	**1,351**	219,727	0
Totals	**$ 1,898,130**	$ 1,325,200	$ 965,090

[1] Project costs are associated with ash pond closures, solid waste landfill construction, and installation of wastewater treatment systems.

[2] Reflects ongoing improvements to existing generating resources and FERC Relicensing. "Other" includes Camp Hall and transmission improvements due to load growth. "Budget 2023-25"General Improvements includes a $5M property acquisition previously reflected separately.

[3] Reflects future generation costs associated with the load and resource plan.

As determined by the Authority, the capital improvement program will be funded from revenues, additional revenue obligations, commercial paper, revolving credit agreements as well as internal funding sources.

Budget

The Authority's 2024 three-year capital budget is as follows:

Years Ending December 31,	2024	2025	2026
		(Millions)	
Environmental Compliance [1]	$ 204.4	$ 129.9	$ 60.9
General System Improvements and Other [2]	460.8	500.3	540.6
Load and Resource Plan [3]	0.3	0.9	0.2
Total Capital Budget [4]	$ 665.5	$ 631.1	$ 601.7

Budget Assumptions:

[1] Project costs are associated with ash pond closures, solid waste landfill construction, and installation of wastewater treatment systems.

[2] Reflects ongoing improvements to existing generating resources and FERC Relicensing. "Other" includes Camp Hall and transmission improvements due to load growth.

[3] Reflects future generation costs associated with the load and resource plan.

[4] Will be financed by internal funds or debt.

Financing Activities

Although there were no new Revenue Obligation Bonds issued or refunded in 2023, the Authority entered into a cash defeasance whereby proceeds were deposited into an escrow account to fund near term maturities due on December 1, 2024. The resulting transaction included removal of approximately $62.7 million in debt outstanding. The principal and interest net debt service savings for December 2023 and year 2024 totaled approximately $65.5 million.

Liquidity and Capital Resources

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

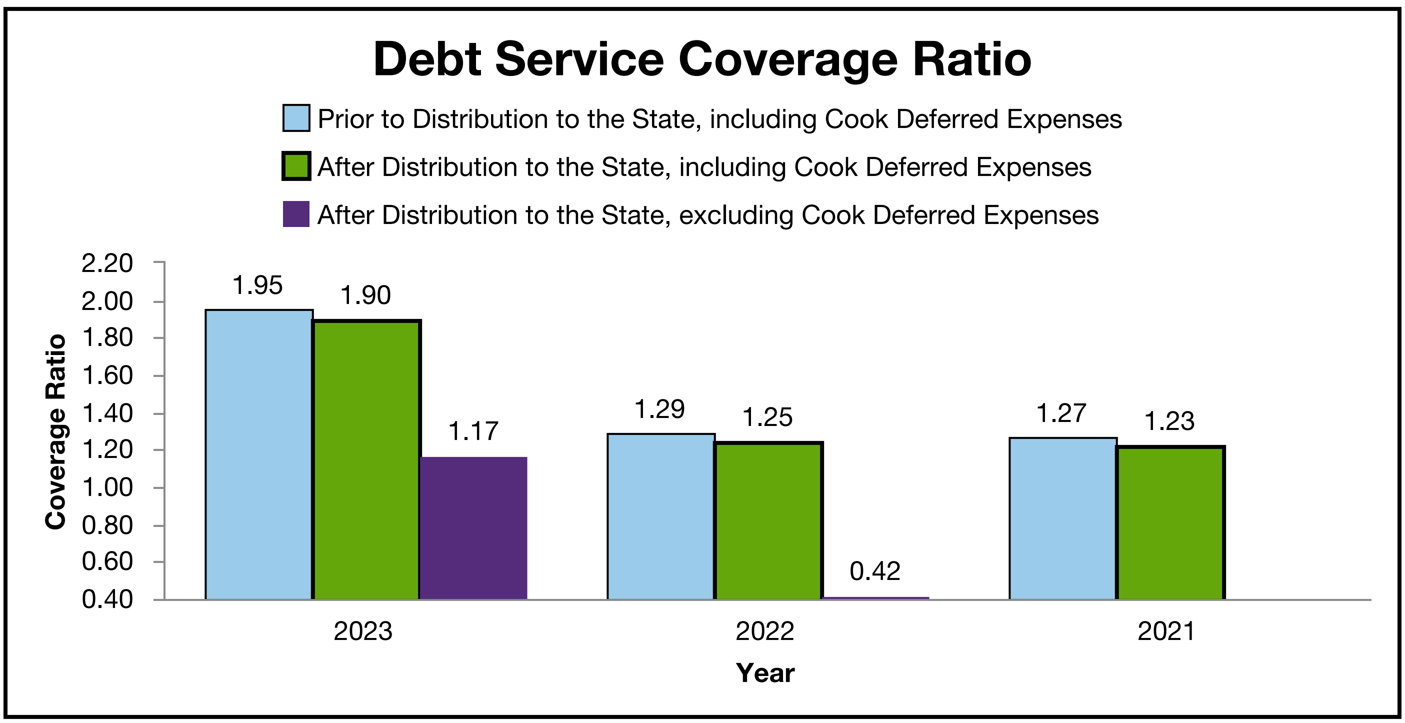
On December 31, 2023, Santee Cooper had $846.6 million of cash and investments, of which $415.1 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $215.9 million.

The Authority has entered into Reimbursement Agreements and secured irrevocable direct-pay letters of credit with a bank facility to support the issuance of commercial paper notes totaling $300.0 million as of December 31, 2023. As of December 31, 2023, the Authority had $183.4 million of commercial paper notes outstanding.

To obtain other funds, if needed, the Authority entered into Revolving Credit Agreements with various bank facilities. These agreements allow the Authority to borrow up to $750.0 million and expire at various dates. As of December 31, 2023, the Authority has borrowed $403.9 million under these agreements.

Debt Service Coverage

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2023, 2022 and 2021 is shown below:



[1] Excluding commercial paper and other.

[2] See Note 5 - *Cook Settlement as to Rates*.

Bond Ratings

Bond ratings assigned by various agencies as of December 31, 2023, 2022 and 2021 were as follows:

Agency / Lien Level	2023	2022	2021
Fitch Ratings			
Revenue Obligations	**A-**	A-	A-
Commercial Paper[1]	**F1**	F1	F1
Outlook	**Negative**	Negative	Stable
Moody's Investors Service, Inc.			
Revenue Obligations	**A3**	A3	A2
Commercial Paper[1]	**P-1**	P-1	P-1
Outlook	**Stable**	Negative	Stable
Standard & Poor's Rating Services			
Revenue Obligations	**A-**	A-	A
Commercial Paper[1]	**A-1**	A-1	A-1
Outlook	**Negative**	Negative	Stable

[1] In 2020, the Authority *amended its* Direct Pay Letters of Credit issued by a financial institution supporting the commercial paper program.

Bond Market Transactions for Years 2023, 2022 and 2021

YEAR 2023

No Bond Market Transactions - South Carolina Public Service Authority did not issue any Revenue Bond Obligations in 2023.

YEAR 2022

Revenue Obligations:	2022 Tax-Exempt Refunding Series A	Par Amount:	$ 930,990,000
Purpose:	Refund a portion of the following: 2013 Series A, 2013 Refunding Series B, 2013 Series E, 2014 Series A, 2014 Refunding Series B, 2014 Refunding Series C, 2015 Series A, 2015 Series E	Date Closed:	February 23, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 3.31 percent		
Revenue Obligations:	2022 Tax-Exempt Refunding Series B	Par Amount:	$ 352,201,000
Purpose:	Refund a portion of the following: 2013 Series A, 2013 Refunding Series B, 2013 Series E, 2014 Series A, 2014 Refunding Series B, 2014 Refunding Series C, 2015 Series A, 2015 Series E	Date Closed:	February 23, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 3.31 percent		
Revenue Obligations:	2022 Tax-Exempt Refunding Series C	Par Amount:	$ 36,640,000
Purpose:	Refund all of the 2016 Series D	Date Closed:	November 15, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 4.85 percent		
Revenue Obligations:	2022 Taxable Refunding Series D	Par Amount:	$ 134,850,000
Purpose:	Refund all of the 2016 Series D	Date Closed:	November 15, 2022
Comments:	Taxable bond with an all-in true interest cost of 6.56 percent		
Revenue Obligations:	2022 Tax-exempt Improvement Series E	Par Amount:	$ 390,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	November 15, 2022
Comments:	Tax-exempt bond with an all-in true interest cost of 5.26 percent		
Revenue Obligations:	2022 Taxable Improvement Series F	Par Amount:	$ 60,000,000
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	November 15, 2022
Comments:	Taxable bond with an all-in true interest cost of 6.47 percent		

YEAR 2021

Revenue Obligations:	2021 Tax-Exempt Refunding Series A	Par Amount:	$ 145,735,000
Purpose:	Refund all the 2011 Refunding Series C and a portion of the 2012 Refunding Series A	Date Closed:	September 2, 2021
Comments:	Tax-exempt bond with an all-in true interest cost of 2.10 percent.		
Revenue Obligations:	2021 Tax-Exempt Improvement Series B	Par Amount:	$ 284,555,000
Purpose:	To finance a portion of the Authority’s ongoing capital program and convert variable debt to fixed-rate debt at a low interest rate	Date Closed:	September 2, 2021
Comments:	Tax-exempt bond with an all-in true interest cost 2.93 percent		

Requests For Information

This financial report is designed to provide a general overview of the South Carolina Public Service Authority’s finances for all those with an interest in the South Carolina Public Service Authority’s finances. Questions concerning any of the information provided in this report or requests for additional information should be addressed to Daniel T. Manes, Controller, South Carolina Public Service Authority, P.O. Box 2946101, Moncks Corner, SC 29461-6106.

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Statements of Net Position - Business - Type Activities
South Carolina Public Service Authority
As of December 31, 2023 and 2022

		2023		2022
		(Thousands)		
ASSETS				
Current assets				
Unrestricted cash and cash equivalents	**$**	**236,702**	$	299,284
Unrestricted investments		**178,390**		163,567
Restricted cash and cash equivalents		**35,904**		53,175
Restricted investments		**264,587**		459,517
Receivables, net of allowance for doubtful accounts of $2,353 and $2,469 at December 31, 2023 and December 31, 2022, respectively		**175,251**		220,458
Materials inventory		**186,373**		171,731
Fuel inventory				
Fossil fuels		**178,484**		100,125
Regulatory Asset - Nuclear		**7,296**		7,911
Prepaid expenses and other current assets		**41,265**		92,972
Total current assets		**1,304,252**		1,568,740
Noncurrent assets				
Restricted cash and cash equivalents		**336**		373
Restricted investments		**130,709**		123,778
Capital assets				
Utility plant		**9,263,588**		9,120,952
Long lived assets - asset retirement cost		**266,981**		266,981
Accumulated depreciation		**(4,891,661)**		(4,619,865)
Total utility plant-net		**4,638,908**		4,768,068
Construction work in progress		**431,202**		214,373
Other physical property-net		**25,502**		25,722
Total capital assets		**5,095,612**		5,008,163
Investment in associated companies		**28,947**		26,057
Costs to be recovered from future revenue		**213,527**		221,960
Regulatory asset - OPEB		**149,694**		152,497
Regulatory asset - nuclear		**3,638,884**		3,670,734
Regulatory assets - Cook Settlement Exceptions		**625,110**		358,605
Other noncurrent and regulatory assets		**130,324**		234,345
Total noncurrent assets		**10,013,143**		9,796,512
Total assets	**$**	**11,317,395**	$	11,365,252
DEFERRED OUTFLOWS OF RESOURCES				
Deferred outflows - pension	**$**	**23,612**	$	69,402
Deferred outflows - OPEB		**56,008**		57,539
Regulatory asset - asset retirement obligation		**557,239**		638,709
Accumulated decrease in fair value of hedging derivatives		**19,348**		25,621
Unamortized loss on refunded and defeased debt		**173,079**		185,440
Total deferred outflows of resources	**$**	**829,286**	$	976,711
Total assets & deferred outflows of resources	**$**	**12,146,681**	$	12,341,963

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

Statements of Net Position - Business - Type Activities - continued
South Carolina Public Service Authority
As of December 31, 2023 and 2022

		2023		2022
		(Thousands)		
LIABILITIES				
Current liabilities				
Current portion of long-term debt	**$**	**56,585**	$	39,525
Accrued interest on long-term debt		**38,770**		40,456
Revolving credit agreement		**1,394**		0
Commercial paper		**183,363**		118,246
Accounts payable		**189,501**		215,268
Other current liabilities		**126,303**		258,789
Total current liabilities		**595,916**		672,284
Noncurrent liabilities				
Construction liabilities		**4,519**		3,781
Net OPEB liability		**150,037**		203,817
Net Pension liability		**302,480**		308,586
Asset retirement obligation liability		**558,786**		630,526
Total long-term debt (net of current portion)		**7,129,966**		7,066,226
Unamortized debt discounts and premiums		**475,585**		507,324
Long-term debt-net		**7,605,551**		7,573,550
Other credits and noncurrent liabilities		**109,089**		92,407
Total noncurrent liabilities		**8,730,462**		8,812,667
Total liabilities	**$**	**9,326,378**	$	9,484,951
DEFERRED INFLOWS OF RESOURCES				
Deferred inflows - pension	**$**	**12,230**	$	61,848
Deferred inflows - OPEB		**52,698**		7,334
Accumulated increase in fair value of hedging derivatives		**54,819**		207,449
Nuclear decommissioning costs		**217,120**		204,486
Regulatory Inflows - Toshiba Settlement		**233,084**		241,976
Total deferred inflows of resources	**$**	**569,951**	$	723,093
NET POSITION				
Net investment in capital assets	**$**	**2,001,334**	$	2,040,738
Restricted for debt service		**12,182**		20,698
Unrestricted		**236,836**		72,483
Total net position	**$**	**2,250,352**	$	2,133,919
Total liabilities, deferred inflows of resources & net position	**$**	**12,146,681**	$	12,341,963

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

Statements of Revenues, Expenses and Changes in Net Position - Business - Type Activities

South Carolina Public Service Authority

For the years ended December 31, 2023 and December 31, 2022

	2023	2022
	(Thousands)	
Operating revenues		
Sale of electricity	**$ 1,825,124**	$ 1,923,763
Sale of water	**7,493**	7,574
Other operating revenue	**17,986**	17,713
Total operating revenues	**1,850,603**	1,949,050
Operating expenses		
Electric operating expenses		
Production	**179,981**	139,015
Fuel	**525,929**	559,432
Purchased and interchanged power	**126,693**	431,585
Transmission	**46,897**	36,828
Distribution	**14,110**	15,546
Customer accounts and other	**18,997**	19,528
Administrative and general	**79,231**	70,182
Electric maintenance expenses	**154,369**	118,973
Water operating and maintenance expenses	**5,937**	4,920
Depreciation	**272,161**	269,073
Sums in lieu of taxes	**5,223**	4,928
Total operating expenses [1]	**1,429,528**	1,670,010
Operating income	**421,075**	279,040
Nonoperating revenues (expenses)		
Interest and investment revenue	**16,939**	6,751
Net increase in fair value of investments	**20,209**	1,230
Interest expense on long-term debt [2]	**(327,034)**	(302,680)
Interest expense on commercial paper and other [3]	**(5,966)**	(7,992)
Amortization income	**17,955**	19,784
Costs to be recovered from future revenue	**(8,433)**	(1,026)
U.S. Treasury subsidy on Build America Bonds	**7,669**	7,669
Regulatory amortization - net	**(23,573)**	(46,427)
Other-net	**16,553**	56,465
Total nonoperating revenues (expenses)	**(285,681)**	(266,226)
Income before transfers	**135,394**	12,814
Transfers		
Distribution to the State	**(18,961)**	(17,675)
Change in net position	**116,433**	(4,861)
Total net position-beginning of period	**2,133,919**	2,138,780
Total net position-ending	**$ 2,250,352**	$ 2,133,919

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

[1] Operating expenses were reduced by $243.2 million in 2023 and $350.2 million in 2022 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

[2] Interest on long-term debt was reduced by $17.3 million in 2023 and $8.4 million in 2022 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

[3] Interest on commercial paper was reduced by $6.0 million in 2023 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

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Statements of Cash Flows - Business - Type Activities

South Carolina Public Service Authority
Years Ended December 31, 2023 and 2022

	2023	2022
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	**$ 1,895,931**	$ 1,907,220
Payments to non-fuel suppliers	**(853,744)**	(384,315)
Payments for fuel	**(615,265)**	(629,329)
Purchased power	**(274,712)**	(688,753)
Payments to employees	**(198,166)**	(222,616)
Other receipts-net	**341,634**	206,190
Net cash provided by operating activities	**295,678**	188,397
Cash flows from non-capital related financing activities		
Distribution to the State	**(18,961)**	(17,675)
Proceeds from revolving credit agreement draw	**185,000**	210,360
Repayment of revolving credit agreement draw	**0**	(10,000)
Proceeds from issuance of commercial paper notes	**116,000**	6,200
Repayment of commercial paper notes	**(20,297)**	(13,533)
Refunding / defeasance of long-term debt	**(27,868)**	(965,763)
Proceeds from sale of bonds	**0**	974,682
Repayment of long-term debt	**(10,628)**	(30,545)
Interest paid on long-term debt	**(186,656)**	(170,672)
Interest paid on commercial paper and other	**(8,023)**	(2,478)
Other-net	**(4,685)**	(5,432)
Net cash provided by (used in) non-capital related financing activities	**23,882**	(24,856)
Cash flows from capital-related financing activities		
Proceeds from revolving credit agreement draw	**0**	9,100
Repayment of revolving credit agreement draw	**(600)**	(12,211)
Proceeds from issuance of commercial paper notes	**15,598**	13,814
Repayment of commercial paper notes	**(46,184)**	(9,067)
Refunding / defeasance of long-term debt	**(34,813)**	(587,653)
Proceeds from sale of bonds	**0**	971,423
Repayment of long-term debt	**(28,897)**	(77,246)
Interest paid on long-term debt	**(159,005)**	(120,886)
Interest paid on commercial paper and other	**(3,530)**	(3,880)
Construction and betterments of utility plant	**(330,926)**	(218,901)
Other-net	**(26,335)**	(9,915)
Net cash used in capital-related financing activities	**(614,692)**	(45,422)
Cash flows from investing activities		
Proceeds from the sale and maturity of investment securities	**921,004**	1,231,963
Purchase of investment securities	**(721,485)**	(1,340,603)
Other-net	**0**	1,230
Interest on investments	**15,723**	5,737
Net cash provided by (used in) investing activities	**215,242**	(101,673)
Net (decrease) increase in cash and cash equivalents	**(79,890)**	16,446
Cash and cash equivalents-beginning	**352,832**	336,386
Cash and cash equivalents-ending	**$ 272,942**	$ 352,832

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

Statements of Cash Flows - Business - Type Activities - continued
South Carolina Public Service Authority
Years Ended December 31, 2023, and 2022

	2023	2022
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	**$ 421,075**	$ 279,040
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation	**272,161**	269,073
Amortization of nuclear fuel	**16,134**	18,619
Net power gains (losses) involving associated companies	**(49,389)**	(250,532)
Distributions from associated companies	**48,648**	249,049
Advances to/from associated companies	**1,764**	2,514
Changes in assets and liabilities		
Accounts receivable-net	**45,207**	(44,648)
Inventories	**(93,001)**	(64,895)
Prepaid expenses	**58,801**	(52,355)
Other deferred debits	**(42,173)**	(368,697)
Accounts payable	**(32,292)**	24,685
Other current liabilities	**(187,945)**	79,733
Other noncurrent liabilities	**(163,312)**	46,811
Net cash provided by operating activities	**$ 295,678**	$ 188,397
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	**$ 236,702**	$ 299,284
Restricted cash and cash equivalents	**35,904**	53,175
Noncurrent		
Restricted cash and cash equivalents	**336**	373
Cash and cash equivalents at the end of the year	**$ 272,942**	$ 352,832
Noncash capital activities-Accounts Payable	**$ 15,391**	$ 8,866

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

Statements of Fiduciary Net Position - OPEB Trust Fund

South Carolina Public Service Authority
As of December 31, 2023, and 2022

	2023	2022
	(Thousands)	
ASSETS		
Cash and cash equivalents	**$ 2,668**	$ 4,239
Investments	**103,351**	85,192
Total assets	**$ 106,019**	$ 89,431
LIABILITIES		
Total liabilities	**$ 0**	$ 0
NET POSITION		
Restricted for other postemployment benefits (OPEB)	**$ 106,019**	$ 89,431
Total net position	**$ 106,019**	$ 89,431
Total liabilities & net position	**$ 106,019**	$ 89,431

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

Statements of Changes in Fiduciary Net Position - OPEB Trust Fund

South Carolina Public Service Authority
Years Ended December 31, 2023 and 2022

	2023	2022
	(Thousands)	
ADDITIONS		
Employer contributions	**$ 12,804**	$ 9,578
Total employer contributions	**12,804**	9,578
Investment income (loss)		
Appreciation (depreciation) in fair value of investments	**253**	(32,722)
Interest	**3,531**	2,832
Net investment income (loss)	**3,784**	(29,890)
Total additions	**16,588**	(20,312)
DEDUCTIONS		
Total deductions	**0**	0
Change in net position	**16,588**	(20,312)
Net position - beginning of period	**89,431**	109,743
Total net position - ending	**$ 106,019**	$ 89,431

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

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 (the "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 services 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. The Authority's financial statements include the accounts of the electric system and the Lake Moultrie and Lake Marion Regional Water Systems after elimination of inter-company accounts and transactions.

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 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 Statements of Net Position and 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.

E - Cash and Cash Equivalents - For purposes of the Statements of Net Position and 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 constructions. Due to the adoption of GASB 89, *Accounting for Interest Cost Incurred Before the End of Construction Period*, interest is no longer capitalizable subsequent to 2020. Those 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. 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,	**2023**	2022
Annual average depreciation	**3.1%**	3.0%

I - Retirement of Long Lived Assets - The Authority follows the guidance of GASB 83, *Certain Asset Retirement Obligations (ARO),* in regard to the decommissioning of V.C. Summer Nuclear Station ("Summer Nuclear Unit 1") as a minority owner (less than 50%) of applicable jointly owned generation facilities and for closing coal-fired generation ash ponds. The Authority uses the measurement produced by the nongovernmental minority owner that has operational responsibility for Summer Nuclear Unit 1 (ARO Measurement), to account for it's ARO, which is included in non-current liabilities on the Balance Sheet

Summer Nuclear Unit 1
As required by the Nuclear Regulatory Commission ("NRC") and in accordance with prudent utility practices, Santee Cooper systematically sets aside funds to provide for the eventual decommissioning of Summer Nuclear Unit 1. The annual decommissioning funding deposit amount is currently based on NRC requirements, estimated cost escalation and fund earnings rates, the results of a site-specific decommissioning study conducted by an outside firm, estimated Department of Energy ("DOE") reimbursement of spent fuel energy storage costs and a SAFSTOR (delayed decommissioning) scenario. This site-specific study also forms the basis for the asset retirement obligation calculation presented in the table below. The estimated remaining useful life of Summer Nuclear Unit 1 is expected to end in 2062.

Coal Combustion Residuals ("CCRs")
The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, and gypsum. These wastes, known as CCRs, are exempt from hazardous waste regulation under the Resource Conservation and Recovery Act ("RCRA"). On April 17, 2015, EPA published the CCR Rule establishing comprehensive requirements for the management and disposal of CCRs. The Rule regulates CCRs as a RCRA Subtitle D, nonhazardous waste and had an effective date of October 19, 2015. The Authority continues to comply with the CCR Rule through groundwater monitoring, assessment of corrective measures and internet postings of CCR Rule reports. Long-term compliance plans to address groundwater include pond closures and utilization of Class 3 landfills at the Cross and Winyah Generating Stations for disposal of CCRs.

The Authority has ash ponds at Cross, Winyah, and Jefferies Generating Stations and gypsum ponds at Cross and Winyah Generating Stations. Closure plans for the Jefferies Generating Station ash ponds and for the Winyah West Ash Pond have been approved by the Department of Health and Environmental Control ("DHEC") and closure is in progress, with regulatory deadlines of 2030. These ponds are currently not subject to the CCR Rule. However, CCR rulemakings changes could regulate these impoundments and possibly the now closed Grainger ash ponds as being subject to the CCR Rule. The Cross Bottom Ash Pond and the remaining ponds at the Winyah Generating Station (A Ash Pond, B Ash Pond, South Ash Pond and Unit 3 & 4 Slurry Pond) are subject to the CCR Rule's closure requirements and are subject to DHEC closure regulations. Plans are being developed and implemented to facilitate closure of the remaining ponds by the CCR Rule's regulatory deadlines with application for extensions if necessary. The ponds will be closed through excavation and beneficial use of materials or through disposal in the on-site industrial Class 3 solid waste landfills.

Two additional ponds (Winyah Slurry Pond 2 and the Cross Gypsum Pond) are also subject to the CCR Rule and have already completed closure in accordance with DHEC's requirements. Volumetric calculations have been conducted by the Authority to determine estimated volumes to be removed. Cost estimates are applied to the volumes to estimate the asset retirement obligation as presented in the table below.

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,		**2023**			2022	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 451.9**	**$ 178.6**	**$ 630.5**	$ 439.5	$ 229.9	$ 669.4
Accretion expense	**12.8**	**3.3**	**16.1**	12.4	4.3	16.7
Adjustments/Removals/Settlements	**(60.7)**	**(27.1)**	**(87.8)**	0	(55.6)	(55.6)
Balance as of December 31,	**$ 404.0**	**$ 154.8**	**$ 558.8**	$ 451.9	$ 178.6	$ 630.5
Asset Retirement Cost (ARC):	**$ 96.5**	**$ 170.4**	**$ 266.9**	$ 96.5	$ 170.4	$ 266.9
Regulatory Asset - ARO	**$ 403.8**	**$ 153.4**	**$ 557.2**	$ 461.7	$ 177.0	$ 638.7

J – Closure and Post Closure Care Costs - The Authority follows the guidance of GASB 18, *Accounting for Municipal Solid Waste Landfill Closure and Post-closure Care Costs*, in accounting for the closure and post-closure care costs associated with Cross and Winyah Generating Stations landfills (the "landfills"). State and federal laws and regulations require the Authority to place a final cover on its landfills when it stops accepting waste and to perform certain maintenance and monitoring functions at the site for thirty years after closure. Although closure and post-closure care costs will be paid only near or after the date the landfill stops accepting waste, the Authority reports a portion of these closure and post-closure care costs as an operating expense in each period based on landfill capacity used as of each balance sheet date. The landfill closure and post-closure expenses at December 31, 2023 and 2022 were $22.6 million and $17.0 million, respectively, which are included as part of electric operating expenses, and represent a cumulative amount reported to date based on the use of 21% of the total permitted capacity of the Cross Landfill Area 1B, 76% of the total permitted capacity of the Winyah Landfill Area 1, and 15% of Winyah Landfill Area 2. The Authority will recognize the remaining estimated cost of closure and post-closure care for these landfill areas of $51.9 million as the remaining estimated capacity is filled. These amounts are based on what it would cost to perform all closure and post-closure care in 2023. The landfill closure and post-closure care liabilities at December 31, 2023 and 2022 were $16.5 million and $10.9 million. Based on current fill rates, the Authority expects to close the existing Cross landfill cell in 2058. Future, already permitted landfill cells will be constructed, operated, and then closed on an on-going basis, as needed for the life of the plant. The Authority plans to close the Winyah Landfill Area 1 in 2024. Winyah Landfill Area 2 is expected to close by 2035 once pond closure activities are complete and the Winyah units are retired. Actual closure costs may be higher due to inflation, changes in technology, or changes in regulations.

In 2023, the Authority has met the requirements of a local government financial test that is one option under State and federal laws and regulations to help determine if a unit is financially able to meet closure and post closure care requirements.

K - Reporting Impairment Losses - The Authority follows the guidance of GASB 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*, in determining if a capital asset has been impaired and the accounting treatment of such impairment. An impairment is a significant, unexpected decline in the service utility of a capital asset. Events or changes in circumstances that may be indicative of impairment include evidence of physical damage, enactment or approval of laws or regulations or other changes in environmental factors, technological changes or evidence of obsolescence, changes in the manner or duration of use of a capital asset, and construction stoppage. A capital asset generally should be considered impaired if both (a) the decline in service utility of the capital asset is large in magnitude and (b) the event or change in circumstance is outside the normal life cycle of the capital asset. Impaired capital assets that will no longer be used are reclassified from plant balances and CWIP to another asset category and reported at the lower of carrying value or fair value.

There were no new impairment losses for 2023 or 2022.

L- Other Regulatory Items - In accordance with GASB 62's guidance on regulated operations, regulated accounting rules may be applied to business type activities that have regulated operations if certain criteria are met. GASB 65, paragraph 29, further clarified regulatory accounting rules under GASB 62. Under regulatory accounting a regulated utility may defer recognition of expenses or revenues if certain criteria are met and the revenues and expenses will be included in future rates. Significant regulatory items are presented as follows:

Regulatory Assets - Summer Nuclear Units 2 and 3
On December 11, 2017, the Board approved the use of regulatory accounting for a portion of the nuclear post-suspension interest balance of $37.1 million. Accordingly, $386,000 and $33,000 was amortized in 2023 and 2022. The remaining balance outstanding at December 31, 2023 was $36.7 million.

On January 22, 2018, the Board approved the use of regulatory accounting for costs incurred related to the impairment of Summer Nuclear Units 2 and 3. The Board gave approval to write-off the total asset balance of $4.211 billion and use regulatory accounting to align with the debt service collected in rates. Accordingly, $32.1 million and $55.5 million was amortized in 2023 and 2022, respectively. The remaining balance outstanding at December 31, 2023 was $3.610 billion.

Deferred Inflows of Resources – Toshiba Settlement
On December 11, 2017, the Board approved use of regulatory accounting to defer recognition of income from the Toshiba Settlement Agreement. As a result, the Authority recorded a regulatory deferred inflow of $898.2 million. The deferred inflow will be amortized to align with the manner in which debt service is reduced as a result of using the proceeds. During 2023 and 2022 $8.9 million and $9.1 million, respectively was amortized. The remaining balance outstanding at December 31, 2023 was $233.1 million.

Regulatory Asset - Cook Settlement Exceptions
On June 27, 2022, the Board authorized the use of regulatory accounting for the 2020 & 2021 Cook Rate Freeze Exceptions Costs (See Note 5 - *Cook Settlement as to Rates*) identified in the Authority's 2020 & 2021 Annual Cook Compliance Reports allowing the Authority to create a regulatory asset (the "Cook Settlement Exceptions Regulatory Asset") and to defer recognition on its Statement of Revenues, Expenses and Changes in Net Position of the expenses associated with those exceptions that qualify for such regulatory accounting treatment, including any future adjustments to the amount of such expenses (the "Cook Deferred Expenses"). In addition, on August 28, 2023, the Board authorized the use of regulatory accounting for the 2022 Cook Rate Freeze Exceptions for new Exceptions that were not previously approved on June 27, 2022. As of December 31, 2023, the Authority recorded a total of $625.1 million of Cook Deferred Expenses in the regulatory account associated with the Cook Settlement Exception Regulatory Asset.

Regulatory Asset - OPEB
On October 13, 2017, the Board approved the use of regulatory accounting to offset the initial unfunded OPEB liability resulting from implementation of GASB 75. As a result, the Authority recorded a regulatory asset of $165.2 million. The regulatory asset is being amortized to expense in accordance with a Level Dollar, 30-year closed amortization period funding schedule provided by the Actuary. The remaining balance outstanding at December 31, 2023 was $149.7 million.

M - Investment in Associated Companies - The Authority is a member (17.65%) of The Energy Authority ("TEA"). The other members are City Utilities of Springfield (Missouri), Gainesville Regional Utilities (Florida), American Municipal Power (Ohio), JEA (Florida), MEAG Power (Georgia) and Nebraska Public Power District (Nebraska).

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,		**2023**		2022
		(Thousands)		
TEA Investment:				
Balance as of January 1,	**$**	**25,935**	$	21,834
Reduction to power costs and increases in electric revenues		**51,409**		253,150
Less: Distributions from TEA		**48,647**		249,049
Balance as of December 31,	**$**	**28,697**	$	25,935
Due To/Due From TEA:				
Payable to	**$**	**35,097**	$	104,645
Receivable from	**$**	**3,623**	$	21,581

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. 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, 2023, the trade guarantees are an amount not to exceed Santee Cooper's share of approximately $128.4 million.

N - Deferred Outflows / Deferred Inflows of Resources - In addition to assets, the Statements of Net Position report 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 five items meeting this criterion: (1) deferred outflows – pension; (2) deferred outflows – OPEB; (3) Regulatory – asset retirement obligation; (4) accumulated decrease in fair value of hedging derivatives; and (5) unamortized loss on refunded and defeased debt.

In addition to liabilities, the 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 five items meeting this criterion: (1) deferred inflows – pension; (2) deferred inflows – OPEB; (3) accumulated increase in fair value of hedging derivatives; (4) nuclear decommissioning costs; and (5) Regulatory inflows - Toshiba settlement.

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

Years Ended December 31,		2023		2022
		(Thousands)		
Deferred outflows of resources	$	829,286	$	976,711
Deferred inflows of resources	$	569,951	$	723,093

O - 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 Statements of Net Position). Deferral of changes in fair value generally lasts until the transaction involving the hedged item ends.

Core business commodity inputs for the Authority have historically been hedged in an effort to mitigate volatility and cost risk and improve cost effectiveness. Natural gas is a direct input and heating oil is used as a proxy for retail diesel fuel because it is used to power the coal trains. 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, 2023 and 2022 is below:

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's cash flow hedges are categorized as Level 1.

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			**2023**		2022
	Account Classification		(Millions)		
Fair Value					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**32.0**	$	151.9
Heating Oil	Regulatory Assets/ Liabilities		**3.5**		29.9
Changes in Fair Value					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**(119.9)**	$	60.8
Heating Oil	Regulatory Assets/ Liabilities		**(26.5)**		14.1
Recognized Net Gains (Losses)					
Natural Gas	Operating Expense - Fuel	**$**	**(50.4)**	$	119.2
Heating Oil	Operating Expense - Fuel		**9.7**		14.6
Realized But Not Recognized Net Gains (Losses)					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**(1.2)**	$	1.3
Heating Oil	Regulatory Assets/ Liabilities		**0.1**		1.1
Notional					
			MMBTUs		
Natural Gas			**87,314**		130,132
			Gallons (000s)		
Heating Oil			**17,220**		26,208
Maturities					
Natural Gas			**Jan 2024 - Dec 2026**		Jan 2023 - Dec 2026
Heating Oil			**Jan 2024 - Dec 2025**		Jan 2023 - Dec 2025

P - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers but not billed are accrued monthly. Accrued revenue for retail customers totaled $13.8 million in 2023 and $13.3 million in 2022.

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. Currently most municipal and retail fuel adjustments are under the rate freeze schedules (See Note 10 - Legal Matters, Recently Settled Litigation Matters, *Jessica S. Cook et al. v. The Authority* on page, 81 for additional information). Once the rate freeze is completed, most fuel adjustment provisions will be 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 Coordination 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.

The Authority and Central have resolved certain matters relating to the nuclear project through the execution of the Cook Settlement Agreement and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement. Rates to Central and above provisions are impacted by the Cook Settlement Agreement (See Note 5 – *Cook Settlement as to Rates)***.**

Q- Bond Issuance Costs and Refunding Activity - GASB 65 requires that debt issuance costs, other than prepaid insurance, be expensed in the period incurred. In order to align the impact of this pronouncement 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.

Unamortized debt discounts and premiums 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.

R- 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 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 2023 and 2022 totaled approximately $19.0 million and $17.7 million, respectively.

S - New Accounting Standards –

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 94	**Public-Private and Public-Public Partnerships and Availability Payment Arrangements**	Reviewed and deemed not applicable
Issue Date: March 2020	Effective for periods beginning after June 15, 2022	
Description:	The primary objective of this Statement is to improve financial reporting by addressing issues related to public-private and public-public partnership arrangements (PPPs). As used in this Statement, a PPP is an arrangement in which a government (the transferor) contracts with an operator (a governmental or nongovernmental entity) to provide public services by conveying control of the right to operate or use a nonfinancial asset, such as infrastructure or other capital asset (the underlying PPP asset), for a period of time in an exchange or exchange-like transaction. Some PPPs meet the definition of a service concession arrangement (SCA), which the Board defines in this Statement as a PPP in which (1) the operator collects and is compensated by fees from third parties; (2) the transferor determines or has the ability to modify or approve which services the operator is required to provide, to whom the operator is required to provide the services, and the prices or rates that can be charged for the services; and (3) the transferor is entitled to significant residual interest in the service utility of the underlying PPP asset at the end of the arrangement. This Statement also provides guidance for accounting and financial reporting for availability payment arrangements (APAs). As defined in this Statement, an APA is an arrangement in which a government compensates an operator for services that may include designing, constructing, financing, maintaining, or operating an underlying nonfinancial asset for a period of time in an exchange or exchange-like transaction.	
Statement No. GASB 96	**Subscription-Based Information Technology Arrangements**	Reviewed and effect deemed immaterial
Issue Date: May 2020	Effective for periods beginning after June 15, 2022	
Description:	This Statement provides guidance on the accounting and financial reporting for subscription-based information technology arrangements (SBITAs) for government end users (governments). This Statement (1) defines a SBITA; (2) establishes that a SBITA results in a right-to-use subscription asset—an intangible asset—and a corresponding subscription liability; (3) provides the capitalization criteria for outlays other than subscription payments, including implementation costs of a SBITA; and (4) requires note disclosures regarding a SBITA. To the extent relevant, the standards for SBITAs are based on the standards established in Statement No. 87, Leases, as amended.	
Statement No. GASB 99	**Omnibus 2022**	Reviewed and deemed not applicable
Issue Date: June 2022	Effective date: The requirements of this Statement are effective as follows: • The requirements related to extension of the use of LIBOR, accounting for SNAP distributions, disclosures of nonmonetary transactions, pledges of future revenues by pledging governments, clarification of certain provisions in Statement 34, as amended, and terminology updates related to Statement 53 and Statement 63 are effective upon issuance. • The requirements related to leases, PPPs, and SBITAs are effective for fiscal years beginning after June 15, 2022, and all reporting periods thereafter. • The requirements related to financial guarantees and the classification and reporting of derivative instruments within the scope of Statement 53 are effective for fiscal years beginning after June 15, 2023, and all reporting periods thereafter	

Description: The objectives of this Statement are to enhance comparability in accounting and financial reporting and to improve the consistency of authoritative literature by addressing (1) practice issues that have been identified during implementation and application of certain GASB Statements and (2) accounting and financial reporting for financial guarantees. The practice issues addressed by this Statement are as follows:

- Classification and reporting of derivative instruments within the scope of Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments,* that do not meet the definition of either an investment derivative instrument or a hedging derivative instrument
- Clarification of provisions in Statement No. 87, *Leases*, as amended, related to the determination of the lease term, classification of a lease as a short-term lease, recognition and measurement of a lease liability and a lease asset, and identification of lease incentives
- Clarification of provisions in Statement No. 94, *Public-Private and Public-Public Partnerships and Availability Payment Arrangements,* related to (a) the determination of the public-private and public-public partnership (PPP) term and (b) recognition and measurement of installment payments and the transfer of the underlying PPP asset
- Clarification of provisions in Statement No. 96, *Subscription-Based Information Technology Arrangements,* related to the subscription-based information technology arrangement (SBITA) term, classification of a SBITA as a short-term SBITA, and recognition and measurement of a subscription liability
- Extension of the period during which the London Interbank Offered Rate (LIBOR) is considered an appropriate benchmark interest rate for the qualitative evaluation of the effectiveness of an interest rate swap that hedges the interest rate risk of taxable debt
- Accounting for the distribution of benefits as part of the Supplemental Nutrition Assistance Program (SNAP)
- Disclosures related to nonmonetary transactions
- Pledges of future revenues when resources are not received by the pledging government
- Clarification of provisions in Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments,* as amended, related to the focus of the government-wide financial statements
- Terminology updates related to certain provisions of Statement No. 63, Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position
- Terminology used in Statement 53 to refer to resource flows statements.

Statement No. GASB 100 **Accounting Changes and Error Corrections – an amendment of GASB Statement No. 62** Under review

Issue Date: June 2022 Effective for periods beginning after June 15, 2023

Description: The primary objective of this Statement is to enhance accounting and financial reporting requirements for accounting changes and error corrections to provide more understandable, reliable, relevant, consistent, and comparable information for making decisions or assessing accountability.

This Statement defines *accounting changes* as changes in accounting principles, changes in accounting estimates, and changes to or within the financial reporting entity and describes the transactions or other events that constitute those changes. As part of those descriptions, for (1) certain changes in accounting principles and (2) certain changes in accounting estimates that result from a change in measurement methodology, a new principle or methodology should be justified on the basis that it is preferable to the principle or methodology used before the change. That preferability should be based on the qualitative characteristics of financial reporting—understandability, reliability, relevance, timeliness, consistency, and comparability. This Statement also addresses corrections of errors in previously issued financial statements.

Statement No. GASB 101	**Compensated Absences**	Under review
Issue Date: June 2022	Effective for periods beginning after December 15, 2023	
Description:	The objective of this Statement is to better meet the information needs of financial statement users by updating the recognition and measurement guidance for compensated absences. That objective is achieved by aligning the recognition and measurement guidance under a unified model and by amending certain previously required disclosures. This Statement requires that liabilities for compensated absences be recognized for (1) leave that has not been used and (2) leave that has been used but not yet paid in cash or settled through noncash means. A liability should be recognized for leave that has not been used if (a) the leave is attributable to services already rendered, (b) the leave accumulates, and (c) the leave is more likely than not to be used for time off or otherwise paid in cash or settled through noncash means. Leave is attributable to services already rendered when an employee has performed the services required to earn the leave. Leave that accumulates is carried forward from the reporting period in which it is earned to a future reporting period during which it may be used for time off or otherwise paid or settled. In estimating the leave that is more likely than not to be used or otherwise paid or settled, a government should consider relevant factors such as employment policies related to compensated absences and historical information about the use or payment of compensated absences. However, leave that is more likely than not to be settled through conversion to defined benefit postemployment benefits should not be included in a liability for compensated absences. This Statement requires that a liability for certain types of compensated absences —including parental leave, military leave, and jury duty leave—not be recognized until the leave commences. This Statement also requires that a liability for specific types of compensated absences not be recognized until the leave is used	
Statement No. GASB 102	Certain Risk Disclosures	Under review
Issue Date: December 2023	Effective for periods beginning after June 15,2024	
Description:	State and local governments face a variety of risks that could negatively affect the level of service they provide or their ability to meet obligations as they come due. Although governments are required to disclose information about their exposure to some of those risks, essential information about other risks that are prevalent among state and local governments is not routinely disclosed because it is not explicitly required. The objective of this Statement is to provide users of government financial statements with essential information about risks related to a government's vulnerabilities due to certain concentrations or constraints. This Statement defines a concentration as a lack of diversity related to an aspect of a significant inflow of resources or outflow of resources. A constraint is a limitation imposed on a government by an external party or by formal action of the government's highest level of decision-making authority. Concentrations and constraints may limit a government's ability to acquire resources or control spending. This Statement requires a government to assess whether a concentration or constraint makes the primary government reporting unit or other reporting units that report a liability for revenue debt vulnerable to the risk of a substantial impact. Additionally, this Statement requires a government to assess whether an event or events associated with a concentration or constraint that could cause the substantial impact have occurred, have begun to occur, or are more likely than not to begin to occur within 12 months of the date the financial statements are issued. If a government determines that those criteria for disclosure have been met for a concentration or constraint, it should disclose information in notes to financial statements in sufficient detail to enable users of financial statements to understand the nature of the circumstances disclosed and the government's vulnerability to the risk of a substantial impact.	

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,	**2023**	2022
	(Millions)	
CTBR regulatory asset:		
Balance	**$ 213.5**	$ 222.0
CTBR expense/(reduction to expense):		
Net Expense	**$ 8.4**	$ 1.0

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2023 and 2022 was as follows:

	Beginning Balances	**Increases**	**Decreases**	**Ending Balances**
		Year 2023 (Thousands)		
Utility Plant [1]	**$ 9,120,952**	**$ 184,701**	**$ (42,065)**	**$ 9,263,588**
Long lived assets-asset retirement cost	**266,981**	**0**	**0**	**266,981**
Accumulated depreciation	**(4,619,865)**	**(311,317)**	**39,521**	**(4,891,661)**
Total utility plant-net	**4,768,068**	**(126,616)**	**(2,544)**	**4,638,908**
Construction work in progress	**214,373**	**372,966**	**(156,137)**	**431,202**
Other Physical property-net	**25,722**	**580**	**(800)**	**25,502**
Totals	**$ 5,008,163**	**$ 246,930**	**$ (159,481)**	**$ 5,095,612**

	Beginning Balances	Increases	Decreases	Ending Balances
		Year 2022 (Thousands)		
Utility Plant [1]	$ 8,906,481	$ 301,304	$ (86,833)	$ 9,120,952
Long lived assets-asset retirement cost	266,981	0	0	266,981
Accumulated depreciation	(4,422,072)	(273,647)	75,854	(4,619,865)
Total utility plant-net	4,751,390	27,657	(10,979)	4,768,068
Construction work in progress	331,065	171,228	(287,920)	214,373
Other Physical property-net	26,492	0	(770)	25,722
Totals	$ 5,108,947	$ 198,885	$ (299,669)	$ 5,008,163

[1] Utility Plant includes $113 million for nuclear fuel in 2023 and $101 million in 2022.

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, 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,	**2023**			2022		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 67,710**	**$ 32,064**	**$ 99,774**	$ 58,773	$ 10,997	$ 69,770
Debt Reduction	**10,760**	**6,890**	**17,650**	2,463	12,867	15,330
Funds from Taxable Borrowings	**1,129**	**33,978**	**35,107**	23,215	35,911	59,126
General Improvement	**4**	**0**	**4**	3	0	3
Internal Nuclear Decommissioning Fund	**887**	**83,966**	**84,853**	93	79,204	79,297
Nuclear Fuel	**14,707**	**0**	**14,707**	993	0	993
Revenue and Operating	**96,098**	**250**	**96,348**	179,983	250	180,233
Special Reserve and Other	**45,407**	**21,242**	**66,649**	33,761	24,338	58,099
Total	**$ 236,702**	**$ 178,390**	**$ 415,092**	$ 299,284	$ 163,567	$ 462,851
Current Restricted:						
Debt Service Funds	**$ 22,646**	**$ 28,307**	**$ 50,953**	$ 34,440	$ 26,713	$ 61,153
Funds from Tax-exempt Borrowings	**10,358**	**209,651**	**220,009**	15,835	408,342	424,177
Special Reserve and Other	**2,900**	**26,629**	**29,529**	2,900	24,462	27,362
Total	**$ 35,904**	**$ 264,587**	**$ 300,491**	$ 53,175	$ 459,517	$ 512,692
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 336**	**$ 130,709**	**$ 131,045**	$ 373	$ 123,778	$ 124,151
Total	**$ 336**	**$ 130,709**	**$ 131,045**	$ 373	$ 123,778	$ 124,151
TOTAL FUNDS	**$ 272,942**	**$ 573,686**	**$ 846,628**	$ 352,832	$ 746,862	$ 1,099,694
Cash and investments as of December 31, consisted of the following:						
Cash/Deposits			**$ 22,350**			$ 32,187
Investments			**824,278**			1,067,507
Total cash and investments			**$ 846,628**			$ 1,099,694

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 and separately held 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. Certificates of Deposit 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 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,	**2023**	2022
Total Portfolio	(Billions)	
Total investments	**$ 0.8**	$ 1.1
Purchases	**26.9**	28.5
Sales	**27.2**	28.3
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 215.6**	$ 203.1
Purchases	**242.0**	140.7
Sales	**235.7**	133.6
Unrealized holding gain/(loss)	**6.1**	(48.7)
Repurchase Agreements[1]	(Millions)	
Balance at December 31	**$ 100.0**	$ 100.0

[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, 2023 and 2022, 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, 2023 and 2022, 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, 2023 and 2022, 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, 2023 and 2022 were as follows:

Security Type / Issuer	Fair Value	
	2023	2022
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 119,744**	$ 187,998
Federal National Mortgage Association	**Less than 5%**	Less than 5%
Federal Farm Credit Bank	**97,236**	122,721
Federal Home Loan Mortgage Corp	**58,018**	Less than 5%

Risk Type	Exposure
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, 2023 and 2022:

		Investment Maturities as of December 31, 2023			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
			(Thousands)		
Collateralized Deposits	**$ 97,567**	**$ 97,567**	**$ 0**	**$ 0**	**$ 0**
Repurchase Agreements	**100,000**	**100,000**	**0**	**0**	**0**
Federal Agency Discount Notes	**15,142**	**15,142**	**0**	**0**	**0**
Federal Agency Securities	**289,586**	**74,224**	**68,331**	**78,925**	**68,106**
US Treasury Bills, Notes and Strips	**321,983**	**245,169**	**57,048**	**7,135**	**12,631**
	$ 824,278	**$ 532,102**	**$125,379**	**$ 86,060**	**$ 80,737**

		Investment Maturities as of December 31, 2022			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
			(Thousands)		
Collateralized Deposits	$ 143,793	$ 143,543	$ 250	$ 0	$ 0
Repurchase Agreements	100,000	100,000	0	0	0
Federal Agency Discount Notes	112,492	112,492	0	0	0
Federal Agency Securities	237,561	62,684	30,945	56,989	86,943
US Treasury Bills, Notes and Strips	473,661	232,186	222,339	6,851	12,285
	$1,067,507	$ 650,905	$253,534	$ 63,840	$ 99,228

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the external Nuclear Decommissioning Trust and internal Nuclear Decommissioning Fund. Together these accounts hold $31.0 million par in U.S. Treasury Strips ranging in maturity from August 15, 2029 to May 15, 2039. The accounts also hold $9.2 million par in government agency zero coupon securities in the two portfolios ranging in maturity from May 15, 2024 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. Based on the Authority's current decommissioning assumptions, it is anticipated that none of the invested decommissioning funds will be needed prior to 2062. 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, 2023 and 2022:

		Level		
2023	**Total**	**1**	**2**	**3**
		(Thousands)		
Collateralized Deposits	**$ 97,567**	**$ 0**	**$ 97,567**	**$ 0**
Repurchase Agreements	**100,000**	**0**	**100,000**	**0**
Federal Agency Discount Notes	**15,142**	**0**	**15,142**	**0**
Federal Agency Securities	**289,586**	**0**	**289,586**	**0**
US Treasury Bills, Notes and Strips	**321,983**	**0**	**321,983**	**0**
	$ 824,278	**$ 0**	**$ 824,278**	**$ 0**

		Level		
2022	Total	1	2	3
		(Thousands)		
Collateralized Deposits	$ 143,793	$ 0	$ 143,793	$ 0
Repurchase Agreements	100,000	0	100,000	0
Federal Agency Discount Notes	112,492	0	112,492	0
Federal Agency Securities	237,561	0	237,561	0
US Treasury Bills, Notes and Strips	473,661	0	473,661	0
	$ 1,067,507	$ 0	$ 1,067,507	$ 0

Collateralized Deposit and Repurchase Agreements classified in Level 2 are valued using pricing based on the securities' relationship to benchmark quoted prices.

Fiduciary Funds – 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. In 2018 with the implementation of GASB 75, the Authority established a formal funding plan and elected to fund the OPEB obligation over a 30-year closed period. This method of funding results in a lower OPEB liability and establishes a method of amortizing of the regulatory asset as funding occurs.

For the OPEB Trust, the 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, 2023 and 2022, all of the agency securities held by the OPEB Trust 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, 2023 and 2022, all of the OPEB Trust's investment securities are held by the Trustee or Agent of the OPEB Trust 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, 2023 and 2022, the OPEB Trust 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 OPEB Trust investments at December 31, 2023 and 2022 were as follows:

Security Type / Issuer	Fair Value 2023	Fair Value 2022
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 23,438**	$ 20,813
Federal National Mortgage Association	**Less than 5%**	Less than 5%
Federal Farm Credit Bank	**33,498**	29,008
Federal Home Loan Mortgage Corp	**17,036**	12,954

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 following table shows the distribution of the OPEB Trust's investments by maturity as of December 31, 2023 and 2022:

		Investment Maturities as of December 31, 2023			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
			(Thousands)		
Federal Agency Securities	**79,067**	**0**	**3,682**	**10,369**	**65,016**
Government Securities	**24,239**	**0**	**16**	**0**	**24,223**
	$ 103,306	**$ 0**	**$ 3,698**	**$ 10,369**	**$ 89,239**

		Investment Maturities as of December 31, 2022			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
			(Thousands)		
Federal Agency Securities	65,811	0	999	0	64,812
Government Securities	19,426	0	0	0	19,426
	$ 85,237	$ 0	$ 999	$ 0	$ 84,238

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 OPEB Trust 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 OPEB Trust had the following recurring fair value measurements as of December 31, 2023 and 2022:

		Level		
2023	**Total**	**1**	**2**	**3**
		(Thousands)		
Federal Agency Securities	**79,067**	**0**	**79,067**	**0**
Government Securities	**24,239**	**0**	**24,239**	**0**
	$ 103,306	**$ 0**	**$ 103,306**	**$ 0**

		Level		
2022	Total	1	2	3
		(Thousands)		
Federal Agency Securities	65,811	0	65,811	0
Government Securities	19,426	0	19,426	0
	$ 85,237	$ 0	$ 85,237	$ 0

Note 5 – Cook Settlement as to Rates

On July 31, 2020, the Board authorized management to implement the terms of the Cook Settlement Agreement which provides, in part, for Settlement Rates (defined below) that are effective beginning in August of 2020 and continuing (i) for the customers other than Central Electric Power Cooperative, Inc. ("Central") whose rates are subject to the Rate Freeze, through all bills rendered on or before January 15, 2025, and (ii) for Central, through service rendered on or before December 31, 2024. The respective periods are referred to as the "Rate Freeze Period."

The rate freeze agreed to by the Authority is consistent with rates and the rate stabilization period that was set forth in the Authority's original plan for reform, restructuring, and changes in operations submitted to the South Carolina Department of Administration ("DOA") in November 2019 as part of the State's evaluation of whether or not to sell some or all of the Authority. The Authority's plan was subsequently modified by the Authority following discussions with the DOA and Central. On January 24, 2020, the Authority submitted its plan dated January 3, 2020 to the South Carolina General Assembly pursuant to Act No. 95 of 2019 (the "2019 Reform Plan"). The 2019 Reform Plan identified a series of changes to the Authority's generation and transmission systems as well as expense management and other initiatives intended to achieve cost savings and optimize efficient operations.

The 2019 Reform Plan also included a financial forecast that projected future revenue and expenses. The forecast projected three major "adjustments" to the primary rate components (energy and demand charges) impacting most customers: (1) the fuel adjustment, (2) demand sales adjustment, and (3) economic development sales adjustment. The purpose of these adjustments is to "true up" their values to "actual" base rates. Under normal conditions these values are calculated and then applied to customer bills monthly. As part of the Cook Settlement Agreement, however, these values for the impacted customers are fixed through the Rate Freeze Period.

In accordance with the terms of the Cook Settlement Agreement, the Board authorized management to freeze certain rate schedules and suspend the existing variable rate components of select rates and replace them with those established in the Cook Settlement Agreement during the Rate Freeze Period (the "Settlement Rates"). The Settlement Rates impact a majority of the Authority's customers and freeze the majority of Central's rate components to those established in Schedule A of the Cook Settlement Agreement, and most variable rate components for the majority of the Authority's non-Central customers to those projected in Schedule B of the Cook Settlement Agreement. The Settlement Rates suspend the variability of the fuel adjustment, demand sales adjustment, and economic development sales adjustment for customers with rate codes designated on Schedule B of the Cook Settlement Agreement. This results in rates being frozen for almost all residential and commercial customers participating in the Settlement Rates, as well as industrial customers served under the Schedule L rate and the Interruptible and Economy Power Optional riders. The Settlement Rates under Schedule B also apply to customers with contractual rates based on the Municipal Light and Power rate (ML), the cities of Bamberg, Georgetown, and Seneca.

As part of the Cook Settlement Agreement, the Authority agreed not to defer any costs and expenses incurred or otherwise appropriately attributable to any year during the Rate Freeze Period to any other year or years during or after the Rate Freeze Period, provided, however, that the Authority may defer to rates charged in years after the Rate Freeze Period just and reasonable costs and expenses incurred during the Rate Freeze Period directly resulting from the specific circumstances or events as enumerated in the Agreement (the "Cook Rate Freeze Exceptions"). The Authority must identify any Cook Rate Freeze Exceptions in annual reports provided by the Authority to the Court of Common Pleas for the Thirteenth Judicial Circuit.

In April 2021, the Authority filed its first Annual Cook Compliance Report which identifies three categories of costs and expense occurring during 2020 that qualify as Cook Rate Freeze Exceptions, including (i) $5.2 million resulting from a change in law due to the COVID-19 pandemic, (ii) $1.2 million resulting from named storm Hurricane Isaias; and (iii) $13.3 million attributed to Central Load Deviations.

In April 2022, the Authority filed its second Annual Cook Compliance Report which identifies eight situations that fall within four categories of costs and expenses occurring during 2021 that qualify as Cook Rate Freeze Exceptions. The four categories include (i) $11.9 million resulting from various changes in law; (ii) $175,000 resulting from named Tropical Storm Elsa; (iii) $43.4 million resulting from the coal mine fire and subsequent change in law that required the mine to remain closed ($37.8 million) and the fire and failure of equipment at Virgil C. Summer Nuclear Generating Station Unit 1 ($5.6 million); and (iv) $15.4 million attributable to Central Load Deviations (collectively, the “2021 Cook Rate Freeze Exceptions”).

On June 27, 2022, the Board authorized the use of regulatory accounting for the 2020 & 2021 Cook Rate Freeze Exceptions Costs identified in the Authority’s 2020 & 2021 Annual Cook Compliance Reports allowing the Authority to create a regulatory asset and to defer recognition on its Statement of Revenues, Expenses and Changes in Net Position of the expenses associated with those exceptions that qualify for such regulatory accounting treatment, including any future adjustments to the amount of such expenses. In addition, on August 28, 2023, the Board authorized the use of regulatory accounting for the 2022 Cook Rate Freeze Exceptions for new Exceptions that were not previously approved on June 27, 2022.

The Authority filed its 2022 Annual Compliance Report covering the period from January 1, 2022 through December 31, 2022 (the “2022 Reporting Period”) on April 28, 2023, demonstrating the Authority’s compliance with the Cook Settlement Agreement. The 2022 Annual Compliance Report identified 11 situations falling within four categories of costs and expenses as Rate Freeze Exceptions. The four categories include (1) approximately $7.6 million resulting from various changes in law; (2) approximately $297 million resulting from fires; (3) approximately $77 million resulting from public enemy (Russian invasion of Ukraine); and (4) approximately $21 million resulting from named storms (collectively, the “2022 Cook Rate Freeze Exceptions”). The 2022 Annual Compliance Report also identified approx. $2.5 million in debt costs directly resulting from the Cook Exceptions Regulatory Asset and adjusted two claimed 2021 Exceptions resulting in a credit of approximately $6.5 million.

The following reflects the Cook Deferred Expenses recorded as the Cook Exceptions Regulatory Asset as of December 31, 2023:

Year Ending December 31:	**2023**	2022
Load Exception – Certain deviations in Central’s actual loads	**$ 13,169,774**	$ 13,169,774
Load Exception Interest – Certain deviation in Central’s actual loads	**8,398,351**	8,398,351
Interest	**23,257,810**	0
Foresight Local Mine Fire – Subsequent change in law that required the mine to stay closed	**455,550,969**	318,533,013
Change in Law	**100,321,871**	12,920,563
VCS 1 Fire	**4,824,460**	4,824,460
Named Storm Events – Hurricane Isaias, Ian and Tropical Storm Elsa, Jasper, and Izzy	**2,345,211**	759,218
Winter Storm - Elliott	**17,241,983**	0
Total Regulatory Asset	**$625,110,429**	$358,605,379

Note 6 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2023 and 2022 consisted of the following:

	2023	2022	Interest Rate(s) [1]	Call Price [2]
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2009 Taxable Series C	**1,305**	1,575	6.224	P&I Plus Make-Whole Premium
2009 Taxable Series F	**100,000**	100,000	5.740	P&I Plus Make-Whole Premium
2010 Series C (Build America Bonds) [3]	**360,000**	360,000	6.454	P&I Plus Make-Whole Premium
2012 Taxable Series E	**159,837**	183,378	4.122-4.551	P&I Plus Make-Whole Premium
2013 Tax-exempt Series A	**107,560**	107,560	5.000-5.500	100
2013 Tax-exempt Refunding Series B	**224,525**	224,525	5.000-5.1250	100
2013 Taxable Series C	**250,000**	250,000	5.784	P&I Plus Make-Whole Premium
2013 Tax-exempt Series E	**275,730**	275,730	5.000-5.500	100
2014 Tax-exempt Series A	**294,970**	294,970	5.000-5.500	100
2014 Tax-exempt Refunding Series B	**22,380**	22,380	5.000	100
2014 Tax-exempt Refunding Series C	**351,625**	351,625	3.000-5.500	100
2014 Taxable Refunding Series D	**16,890**	24,970	3.406-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	**353,110**	363,410	3.000-5.000	100
2015 Tax-exempt Refunding Series B	**0**	23,725	5.000	Non-callable
2015 Taxable Series D	**169,657**	169,657	4.770	P&I Plus Make-Whole Premium
2015 Tax-exempt Series E	**108,125**	108,125	5.250	100
2016 Tax-exempt Refunding Series A	**459,115**	459,115	3.125-5.000	100
2016 Tax-exempt Refunding Series B	**408,705**	408,705	2.750-5.250	100
2016 Tax-exempt Refunding Series C	**48,220**	50,360	3.000-5.000	100
2019 Tax-exempt Refunding Series A [4]	**124,795**	143,200	VRD	100
2020 Tax-exempt Refunding Series A	**333,540**	333,710	3.000-5.000	100
2020 Taxable Refunding Series B	**299,725**	299,725	1.485-2.659	P&I Plus Make-Whole Premium
2021 Tax-exempt Refunding Series A	**144,225**	144,995	4.000-5.000	100
2021 Tax-exempt Series B	**280,170**	280,170	4.000-5.000	100
2022 Tax-exempt Refunding Series A	**929,595**	930,990	4.000-5.000	100
2022 Tax-exempt Refunding Series B	**352,201**	352,201	3.000-5.000	100
2022 Tax-exempt Refunding Series C	**34,470**	36,640	5.000-5.500	100
2022 Taxable Refunding Series D	**127,735**	134,850	5.913-6.436	P&I Plus Make-Whole Premium
2022 Tax-exempt Series E	**386,370**	390,000	5.000-5.750	100
2022 Taxable Series F	**59,505**	60,000	5.913-6.447	P&I Plus Make-Whole Premium
Total Revenue Obligations	**6,784,085**	6,886,291		
Direct Placement Long-Term Revolving Credit Agreement: (matures through 2029)	**402,466**	219,460	N/A	N/A
Less: Current Portion - Long-term Debt	**56,585**	39,525		
Total Long-term Debt - (Net of current portion)	**$7,129,966**	$7,066,226		

[1] Interest Rates apply only to bonds outstanding as of December 31, 2023.

[2] Call Price may only apply to certain maturities outstanding at December 31, 2023.

[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] Interest is based on a weekly rate.

Changes in Long-Term Debt

Long-term debt (LTD) activity for the years ended December 31, 2023 and 2022 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 2023 (Thousands)				
Revenue Obligations	**$ 6,886,291**	**$ 0**	**$ (102,206)**	**$6,784,085**	**$56,585**	**$6,727,500**	**$ 475,585**	**$7,203,085**
Direct Placement Long-Term Revolving Credit Agreement	**219,460**	**185,000**	**(600)**	**403,860**	**1,394**	**402,466**	**0**	**402,466**
Totals	**$ 7,105,751**	**$ 185,000**	**$ (102,806)**	**$7,187,945**	**$57,979**	**$7,129,966**	**$ 475,585**	**$7,605,551**
				YEAR 2022 (Thousands)				
Revenue Obligations	$ 6,642,817	$1,904,681	$(1,661,207)	$6,886,291	$39,525	$6,846,766	$ 507,324	$7,354,090
Direct Placement Long-Term Revolving Credit Agreement	22,211	219,460	(22,211)	219,460	0	219,460	0	219,460
Totals	$ 6,665,028	$2,124,141	$(1,683,418)	$7,105,751	$39,525	$7,066,226	$ 507,324	$7,573,550

Summary of Long-Term Principal and Interest

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

	Revenue Obligations	Long-Term Revolving Credit Agreements	Total Principal	Total Interest [1]	Total
Year Ending December 31,			(Thousands)		
2024	$ 56,585	$ 870	$ 57,455	$ 344,254	$ 401,709
2025	129,905	385,575	515,480	341,067	856,547
2026	151,747	2,029	153,776	316,841	470,617
2027	151,101	1,930	153,031	309,851	462,882
2028	175,705	1,952	177,657	303,289	480,946
2029-2033	1,011,057	8,649	1,019,706	1,388,585	2,408,291
2034-2038	1,150,070	2,855	1,152,925	1,136,996	2,289,921
2039-2043	1,121,661	0	1,121,661	865,683	1,987,344
2044-2048	1,249,689	0	1,249,689	570,746	1,820,435
2049-2053	1,251,796	0	1,251,796	256,078	1,507,874
2054-2056	334,769	0	334,769	24,801	359,570
Total	$ 6,784,085	$ 403,860	$ 7,187,945	$ 5,858,191	$ 13,046,136

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

Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2023 are as follows:

Refunding Description	Outstanding	Original Loss	Unamortized Loss
		(Thousands)	
Feb 2012 Defeasance	$ 0	$749	$301
2013 Refunding Series B	0	14,446	5,131
2013 Refunding Series C	0	4,601	2,381
2014 Refunding Series C & Taxable Refunding Series D	0	32,936	9,879
2015 Refunding Series A	0	21,487	3,389
2015 Series E	0	89	25
2016 Refunding Series A	0	56,068	27,967
2016 Refunding Series B	0	12,873	8,404
2019 Refunding Series A	0	1,747	478
2020 Refunding Series A	0	77	1
2021 CP Partial Redemption	0	846	660
2021 Refunding Series A	0	344	278
2022 Refunding Series A & B	0	124,366	114,185
Total	$ 0	$ 270,629	$ 173,079

Summary of In-Substance Defeasance of Debt Using Only Existing Resources

Defeased debt, cash placed in escrow, and defeased debt outstanding at December 31, 2023 are as follows:

Description of Transaction	Defeased Debt		Cash Placed in Escrow	Defeased Debt Outstanding
			(Thousands)	
12/2022 Cash Defeasance	$ 23,541	2012 Series E		
	24,915	2014 Refunding Series C		
	2,000	2014 Refunding Series D		
	17,720	2015 Refunding Series A		
	20,505	2015 Refunding Series B		
	580	2020 Refunding Series A	$ 190	$ 190
12/2023 Cash Defeasance	$ 23,541	2012 Series E		
	5,155	2014 Refunding Series D		
	10,300	2015 Refunding Series A		
	23,725	2015 Refunding Series B	$ 62,406	$ 62,681
Total			$ 62,596	$ 62,871

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 2022 current portion of long-term debt showing the amounts paid as debt service in 2023.

Analysis of December 31, 2022 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from Revenues	$ 39,525
2022 maturities defeased	0
Total	$ 39,525

Reconciliations of Interest Charges

Years Ended December 31,	**2023**	2022
	(Thousands)	
Reconciliation of interest cost to interest		
Total interest cost	**$ 327,034**	$ 302,680
Interest charged to fuel expense	0	0
Total interest expense on long-term debt	**$ 327,034**	$ 302,680
Reconciliation of interest cost to interest		
Total interest cost	**$ 327,034**	$ 302,680
Accrued interest - current year	**(38,770)**	(40,456)
Accrued interest - prior year	**40,456**	38,324
Interest released by refundings	**(101)**	(17,202)
Cook Exceptions Regulatory Asset	**17,297**	8,398
Year-end manual accrual	**(255)**	(186)
Total interest payments on long term debt	**$ 345,661**	$ 291,558

Debt Service Coverage

Years Ended December 31,	2023	2022
	(Thousands)	
Operating revenues	**$ 1,850,603**	$ 1,949,050
Interest and investment revenue	**16,939**	6,751
Total revenues and income	**1,867,542**	1,955,801
Operating expenses [1]	**(1,429,528)**	(1,670,010)
Depreciation	**272,161**	269,073
Total expenses	**(1,157,367)**	(1,400,937)
Funds available for debt service prior to distribution to the State	**710,175**	554,864
Distribution to the State	**(18,961)**	(17,675)
Funds available for debt service after distribution to the State	**$ 691,214**	$ 537,189
Debt Service on Accrual Basis:		
Principal on long-term debt	**$ 36,431**	$ 125,746
Interest on long-term debt [2]	**327,034**	302,680
Long-term debt service paid from Revenues	**363,465**	428,426
Commercial paper and other principal and interest [3]	**8,994**	9,208
Total debt service paid from Revenues	**$ 372,459**	$ 437,634
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses	**1.95**	1.29
After distribution to the State, including Cook Deferred Expenses	**1.90**	1.25
After distribution to the State, excluding Cook Deferred Expenses	**1.17**	0.42
Including commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses	**1.90**	1.26
After distribution to the State, including Cook Deferred Expenses	**1.85**	1.22
After distribution to the State, excluding Cook Deferred Expenses	**1.13**	0.41

[1] Operating expenses were reduced by $243.2 million in 2023 and $350.3 million in 2022 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

[2] Interest on long-term debt was reduced by $17.3 million in 2023 and $8.4 million in 2022 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

[3] Interest on commercial paper was reduced by $6.0 million in 2023 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

Bond Market Transactions

There were no bond issuances for the year ended December 31, 2023.

Debt Covenant Compliance

As of December 31, 2023, and 2022, management believes 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 commercial paper;
(3) payments made into the Capital Improvement Fund.

As of December 31,	**2023**	2022
Outstanding Revenue Obligations	**$6.8 Billion**	$6.9 Billion
Estimated remaining interest payments	**$5.8 Billion**	$6.1 Billion
Issuance years (inclusive)	**2009 through 2022**	2009 through 2022
Maturity years (inclusive)	**2024 through 2056**	2023 through 2056

Note: Proceeds from these bonds were/will be used to fund a portion of the Authority's ongoing capital program or retire or refund certain outstanding debt of the Authority.

The Authority has outstanding indebtedness subject to the terms of its Master Revenue Obligation Resolution dated April 26, 1999 (Master Resolution), which contains a provision permitting the acceleration of all principal and interest on revenue obligations should there be an Event of Default.

Note 7 – Variable Rate Debt

The Board has authorized the issuance of variable rate debt issued under the Notes Resolution not to exceed twenty 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. As of December 31, 2023, 10% of the Authority's aggregate debt outstanding was variable rate (this includes $125 million of the 2019A variable rate bonds that are not subject to the Board approved cap since they are issued under the Master Bond Resolution). 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 120 days. The information related to commercial paper was as follows:

Years Ended December 31,	**2023**	2022
Commercial paper outstanding (000's)	**$ 183,363**	$ 118,246
Effective interest rate (at December 31)	**5.46%**	4.43%
Average annual amount outstanding (000's)	**$ 156,256**	$ 120,086
Average maturity	**50 Days**	47 Days
Average annual effective interest rate	**5.25%**	1.76%

The Authority currently maintains two reimbursement agreements and four revolving credit agreements. The information related to these agreements was as follows:

Years Ended December 31,	**2023**			2022		
	Capacity	**Unused Capacity**	**Expiration**	Capacity	Unused Capacity	Expiration
			(Thousands)			
Irrevocable Direct Pay Letters of Credit and Reimbursement Agreements:						
	$ 100,000	**$ 96,622**	**September 6, 2024**	$ 100,000	$ 50,691	September 6, 2024
	200,000	**20,015**	**February 28, 2025**	200,000	131,063	February 28, 2025
Revolving Credit Agreements:						
	100,000	**11,900**	**March 25, 2025**	100,000	36,900	March 25, 2025
	200,000	**34,400**	**March 20, 2026**	200,000	121,900	March 20, 2026
	250,000	**99,840**	**March 31, 2026**	200,000	121,740	December 27, 2024
	200,000	**200,000**	**June 28, 2024**	200,000	200,000	June 28, 2024
Total	**$1,050,000**	**$ 462,777**		$1,000,000	$ 662,294	

The Authority also has debt outstanding under Revolving Credit Agreements (RCAs) and Reimbursement Agreements with various bank facilities. The RCAs contain provisions permitting, by written notice, the acceleration of outstanding debt and accrued interest upon the occurrence of an event of default and automatically accelerating debt outstanding under the RCAs without such notice upon the occurrence of an event of default relating to certain acts of bankruptcy or insolvency relating to the Authority (unless such automatic acceleration is waived by the applicable lender). The RCAs also contain provisions permitting the applicable lender upon an event of default to terminate its agreement and refuse to advance further funds and providing that such termination of its agreement will automatically occur upon the occurrence of an Event of Default relating to certain acts of bankruptcy or insolvency relating to the Authority (unless such automatic termination is waived by the applicable lender).

The Reimbursement Agreements similarly contain provisions permitting, by written notice, the acceleration of debt outstanding under the Agreements upon the occurrence of an event of default and automatically accelerating debt outstanding under the Agreements without such notice upon the occurrence of an event of default relating to certain acts of bankruptcy or insolvency relating to the Authority. Each Reimbursement Agreement also contains provisions that permit the Bank upon an event of default to deliver a Final Drawing Notice stating that an event of default has occurred under such Agreement, directing that no additional Series A/AA Notes or Series B/BB Notes, as applicable, be issued and stating that the Letter of Credit for the Series A/AA Notes or Series B/BB Notes, as applicable, will terminate on the earlier of (i) the tenth day following the delivery of such notice and (ii) the date on which the drawing on the applicable Letter of Credit resulting from the delivery of such Final Drawing Notice is honored by the Bank.

In addition, in connection with a letter of credit provided by a bank facility in support of the Authority's Variable Rate Revenue Obligations, 2019 Tax-Exempt Refunding Series A, the Authority has entered into a reimbursement agreement. The Authority's payment obligations to the bank facility under the 2019A Reimbursement Agreement are secured by a lien upon and pledge of Revenues on parity with the pledge securing the Revenue Obligations. The agreement was entered into on November 21, 2019 and expires April 21, 2025.

Note 8 – Summer Nuclear Station

Summer Nuclear Unit 1

The Authority and DESC are parties to a joint ownership agreement providing that the Authority and DESC shall own Unit 1 at the Summer Nuclear Station ("Summer Nuclear Unit 1") with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. DESC is solely responsible for the design, construction, budgeting, management, operation, maintenance and decommissioning of Summer Nuclear 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 Summer Nuclear Unit 1, extending it to August 6, 2042. On August 17, 2023, DESC filed a license renewal application with the NRC on behalf of itself and the Authority to extend the operating license from August 2042 to August 2062.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,	**2023**	2022
	(Millions)	
Plant balances before depreciation	**$ 805.8**	$ 792.5
Accumulated depreciation	**331.0**	323.1
Operation & maintenance expense	**91.2**	75.6

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.

DESC contracted with various outside parties to build a licensed Independent Spent Fuel Storage Installation ("ISFSI"), which was completed and commenced receiving fuel in 2016. Because of the Department of Energy's ("DOE") failure to meet its obligation to dispose of spent fuel, DESC and the Authority are being reimbursed by DOE for a portion of ISFSI project costs. The DOE reimbursements to date equal approximately 75% of the total project costs, and the remaining reimbursement remains under dispute between DESC and the DOE.

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 2020 and the NRC's imposed minimum requirement. Based on these estimates and assuming a SAFSTOR (delayed) decommissioning and an eighty year plant life, the Authority's one-third share of the estimated decommissioning costs of Summer Nuclear Unit 1 equals approximately $439.5 million in 2021 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 assuming a SAFSTOR scenario and eighty year plant life, these funds, which total approximately $215.6 million (adjusted to market) at December 31, 2023, along with investment earnings, additional contributions, and credits from future DOE reimbursements for spent fuel storage, are estimated to provide enough funds for the Authority's one-third share of the total decommissioning cost for Summer Nuclear Unit 1.

Events Relative to Summer Nuclear Units 2 and 3

In January of 2008, the Authority approved a generation resource plan that included the development of two new 1,117 MW nuclear generating units (individually, "Summer Nuclear Unit 2" and "Summer Nuclear Unit 3" and together, "Summer Nuclear Units 2 and 3") at the V.C. Summer Nuclear Generating Station. Summer Nuclear Units 2 and 3 would be jointly-owned by the Authority (45% ownership interest) and, at the time, SCE&G (SCANA's subsidiary; SCANA was acquired by Dominion Energy on January 1, 2019 and established Dominion Energy South Carolina (DESC) as a wholly owned subsidiary of SCANA) (55% ownership interest) (together, the "Owners").

On July 31, 2017, the Authority approved the wind-down and suspension of construction of the Summer Nuclear Units 2 and 3 at the Virgil C. Summer Nuclear Generating Station and the preservation and protection of the site and related components and equipment. The Authority had spent approximately $4.7 billion in construction and interest costs. Upon suspending construction, and in accordance with GASB No. 62, the Authority ceased capitalizing interest expense on the debt incurred to fund Summer Nuclear Units 2 and 3 as of July 31, 2017. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 were determined in accordance with GASB No. 42 to be impaired.

Impairment and Sale of Summer Nuclear Units 2 and 3 Assets

After suspending construction, the Authority sought additional project partners or financial support for Summer Nuclear Units 2 and 3. Finding none, the Authority looked to whether or not it could sell the fuel assets and non-fuel assets comprising Summer Nuclear Units 2 and 3 equipment and commodities. With the exception of certain assets to be repurposed at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the assets were determined in accordance with GASB 42 to be impaired.

Regulatory Accounting for Summer Nuclear Units 2 and 3. Based on the results of a fair value determination of the assets, the write-off of the construction costs and fuel for Summer Nuclear Units 2 and 3 for the year ended December 31, 2017 totaled $4.211 billion. In January of 2018, the Authority approved the use of regulatory accounting for the $4.211 billion impairment write-off. The majority of Summer Nuclear Units 2 and 3 was financed with borrowed funds and for rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. Therefore, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the principal payments on the associated indebtedness.

In December of 2017, the Authority approved the use of regulatory accounting to defer (i) a portion of post-suspension capitalized interest in the amount of $37.1 million to be amortized through November 2056 in order to align with the principal payments on the debt used to pay the interest and (ii) the recognition of income from the settlement agreement with the Toshiba Corporation ("Toshiba") relating to Toshiba's guaranty of certain payment obligations in respect of Summer Nuclear Units 2 and 3 (the "Toshiba Settlement Agreement") in the amount of $898.2 million, to be amortized over time to align with the manner in which the settlement proceeds are used to reduce debt service payments.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2023 Amortization	2018 - 2023 Changes	2023 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($561.3 million)	($40.2 million)	$ 3.610 billion
Nuclear post-suspension interest	Asset	$ 37.1 million	$ (419,000)		$ 36.7 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($678.9 million)	$13.8 million	$ 233.1 million

Sales of Summer Nuclear Units 2 and 3 Assets. During calendar years 2018 - 2023, the Authority sold certain equipment and commodities to third parties. *The Authority expects to use the net proceeds received from the sale of nuclear-related equipment to pay down a portion of its outstanding debt, avoid issuing additional debt as well as for other corporate purposes.* Through December 31, 2023, $89.9 million of materials have been sold.

Note 9 – Contracts with Electric Power Cooperatives

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 19 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 the Coordination Agreement, the Authority is the predominant supplier of energy needs for Central, excluding amounts supplied by Duke to the Upstate Load (Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc.), energy Central receives from the Southeastern Power Administration ("SEPA") and negligible amounts generated and purchased from others. In 2023, revenues pursuant to the Coordination Agreement were 58% of total sales of electricity, consistent with 55% in 2022.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to it. 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 Statements of Revenues, Expenses and Changes in Net Position. In 2023, operating revenues were reduced by $6.6 million related to prior years Central audit issues.

In 2013 the Central and Authority Boards approved an Amendment to the Coordination Agreement. As part of this, Central agreed to extend it's right to terminate the agreement until December 31, 2058. The Coordination 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 Coordination 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. The Authority and Central have resolved certain matters relating to the nuclear project through the execution of the Cook Settlement Agreement (See Note 5 – *Cook Settlement as to Rates*) and continue to conduct business pursuant to the terms of the Settlement and the Coordination Agreement.

The Authority and Central coordinate on joint planning for future resources and identify future resources that may become a Proposed Shared Resource (PSR). Under the terms of the contract with Central, Central can elect to opt-out of a PSR. If Central elects to opt-out of a PSR, both Central and the Authority are then each obligated to provide their respective pro rata share (load ratio share) of the capabilities and capacity the PSR would have provided by each providing a Non-Shared Resource(s) (NSR) to the system. Neither party shares in the cost of the other party's NSR.

In 2020, the Authority and Central jointly conducted a solicitation for solar resources, resulting in 425 MW of Purchase Power Agreements (PPAs) for five solar projects with four counterparties. These purchases were collectively considered a PSR and Central opted out. As a result, both parties entered into separate contracts for their respective share of the output of the projects. Each party's contracts are considered their respective NSR. Santee Cooper is entitled to 27.5% of the capabilities and output of the PPAs and Central is entitled to the remaining 72.5%.

In 2022, the Authority proposed a 1,083 MW natural gas combined cycle unit PSR. Central opted out of this resource and is required to bring an NSR to the system in the minimum amount of 820 MW; Santee Cooper is required to bring an NSR to the system in the minimum amount of 372 MW.

Note 10 – Commitments and Contingencies

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2023. The disclosure of contract obligations shown below is based on the Authority's contract rates and represents management's best estimate of future expenditures under current long-term arrangements. Additional arrangements are expected to meet the Authority's full demand.

Years Ending December 31,		Total Volumes with Options [1]		Contract Volumes [2]
		(Thousands)		
2024	$	215,937	$	204,537
2025		62,215		62,215
2026		60,000		60,000
2027		30,500		30,500
2028		31,500		31,500
Total	$	400,152	$	388,752

[1] Includes tons which the Authority has the option 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, 2023:

Contracts with Power Receipt and Payment Obligations [1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	2 Years	39.7
2	2013	20 Years	414.1
1	2013	10 Years	4.5
1	2023	4 Years	24.1
1	2021	2 Years	10.7
1	2023	4 Years	20.7
1	2023	5 Years	14.3
1	2024	5 Years	20.25
1	2024	5 Years	79.8

[1] Payment required upon receipt of power. Assumes no change in indices or escalation.

The Authority purchases network integration transmission service through transmission agreements with DESC, SOCO and Duke. This network transmission service is used to serve 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 2024 and the total transmission obligations for 2025-2034. The wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations				
		2024		2025-2034
		(Thousands)		
Other Customers	$	5,459	$	53,456
Total	$	5,459	$	53,456

The Authority purchased point to point transmission service through transmission agreements with Southern Company and Duke Energy. This point to point transmission service allows the Authority to import forward purchase power commitments and economically purchase power from the market. The table below shows the transmission obligations in 2024 and the total transmission obligations for 2025-2028 based on projected transmission rates.

Transmission Purchase Obligations				
		2024		2025-2028
		(Thousands)		
Duke	$	3,500	$	25,777
SOCO	$	21,580	$	125,451
Total	$	25,080	$	151,228

Santee Cooper has executed four purchase power agreements with 5-year terms under the Public Utilities Regulatory Policies Act of 1978 (PURPA). Four projects associated with these agreements have reached commercial operation. The project associated with Centerfield Solar, LLC, effective April 18, 2019, reached commercial operation in December 2020; the project associated with Gunsight Solar, LLC, effective April 30, 2019, reached commercial operation in December 2022; and the project associated with Allora Solar, LLC, effective May 19, 2020, reached commercial operation in February 2022 . All three projects have a nameplate capacity of 75 MW.
The project associated with Landrace Holdings, LLC, effective May 19, 2020, with a nameplate capacity of 55 MW, reached commercial operation on December 1, 2023.

In 2020, Santee Cooper issued a Request for Proposals for providing up to 500 MW of solar capacity and energy. Five contracts with terms ranging from 15-20 years were awarded, totaling 425 MW. Santee Cooper and Central each entered into separate purchased power agreements for their respective share of the output. In 2022, one of these purchase power agreements, totaling 75 MW, was terminated. In 2023, an additional purchase power agreement, totaling 75 MW, was terminated.

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 through June 30, 2025, effective July 1, 2020, 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 Unit 1. As of December 31, 2023, these contracts total approximately $83.9 million over the next 9 years.

The Authority successfully negotiated a Contractual Service Agreement with General Electric, effective March 2016, that covers all units at Rainey Generating Station. 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. Based on the latest approved fuel forecast, the contract term extends through 2027 and the Authority's estimated remaining commitment on the contract is $37.1 million, including escalation.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation to supply gas transportation needs for its Rainey Generating Station. The service agreement is for 80,000 dekatherms per day of firm capacity and extends through November 1, 2031. The Authority works with Transco to determine future additional requirements.

Byproducts - Coal combustion products ("CCP"), which include fly ash, bottom ash, and flue gas desulfurization products such as gypsum, are produced when coal is burned to generate electricity. The Authority has entered into contracts for the beneficial use of CCPs and continually looks for new markets and customers for the use of CCPs. The Authority supplies and delivers drywall quality gypsum to American Gypsum ("AG") in Georgetown, South Carolina under a long-term contract that includes minimum and maximum supply volumes. The gypsum is primarily sourced from synthetic gypsum produced at the Cross Generating Station ("CGS") and Winyah Generating Station ("WGS"). Currently and under projected dispatch assumptions, gypsum produced at CGS and WGS does not meet required minimum contract volumes, and shortfalls are obtained from several external sources of both natural and synthetic gypsum. Sources may vary based on availability and cost. Natural gypsum is currently purchased and delivered from International Materials Inc. Synthetic gypsum is currently purchased from Cameron Ag Products, LLC ("Cam Ag"). Cam Ag provides this source via rail from various sources in the Southeast to the Authority's Jefferies Station, from where it is delivered to AG. Additionally, ponded ash is reclaimed from the Authority's ash ponds for use in the cement and concrete industry. This pond ash is sold to multiple cement plants as a replacement for silica and alumina in their process. Dry fly ash is recovered directly from the operating units for use in the concrete industry, and bottom ash is beneficially used by concrete block manufacturers to produce lightweight concrete block. The Authority has multiple beneficial use agreements to facilitate beneficial use activities, one of which is the staged turbulent air reactor ("STAR") Processed Fly Ash Operating and Sales Agreement between the Authority and The SEFA Group, Inc. ("SEFA"). Pursuant to this Agreement, the Authority supplies dry fly ash and/or ponded ash from the Winyah Station to SEFA who processes it in their STAR unit to produce a high-quality fly ash which they market to the concrete industry. In addition, ponded gypsum, which does not meet wallboard specifications, is reclaimed from the Authority's slurry ponds for use in the agriculture and cement industries.

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 2023. Policies are subject to deductibles ranging from $500 to $2.0 million, except for named storm losses which carry deductibles from $2.0 million up to $50.0 million. Also, a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2023, there were minimal payments made for general liability claims.

The Authority is self-insured for auto, 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. Estimated exposure for worker's compensation is based on an annual actuarial study using loss and exposure information valued as of June 30, 2023. In addition, there have been no third-party claims regarding environmental damages for 2023 or 2022.

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,		**2023**		2022
		(Thousands)		
Unpaid claims and claim expense at beginning of year	**$**	**2,684**	$	1,589
Incurred claims and claim adjustment expenses:				
Add: Provision for current year events		**1,066**		1,501
Less: Payments for current and prior years		**1,013**		406
Total unpaid claims and claim expenses at end	**$**	**2,737**	$	2,684

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; and 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 except for employee dental insurance for which the Authority is self-insured. Risk exposure for the dental plan is limited by plan provisions. 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 $16.263 billion by the Price-Anderson Indemnification Act. This $16.263 billion would be covered by nuclear liability insurance of $500.0 million per reactor unit, with potential retrospective assessments of up to $165.9 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $24.7 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 $55.3 million, not to exceed approximately $8.2 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, DESC and the Authority maintain, with Nuclear Electric Insurance Limited ("NEIL"), $1.060 billion primary property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. DESC 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, DESC 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 $6.0 million for the primary policy and $1.5 million for the accidental outage policy.

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, 2023.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with all applicable environmental regulations and standards under the Clean Air Act ("CAA"). The Authority continues to review proposed greenhouse gas regulations and legislation to assess potential impacts to its operations. The latest rulemaking occurred on June 24, 2019, when the EPA issued the final Affordable Clean Energy ("ACE") Rule following the repeal of the Clean Power Plan ("CPP"). The ACE Rule, which established heat rate improvement ("HRI") measures as the best system of emissions reduction ("BSER") for CO_2 emissions from existing coal-fired Electric Generating Units (EGUs), was vacated and remanded by the D.C. Circuit Court of Appeals on January 19, 2021.
On June 30, 2022, the U.S. Supreme Court issued a landmark decision in West Virginia vs. EPA, which reversed the D.C. Circuit and held that Congress did not give the EPA authority under the CAA to regulate CO_2 emissions based on generation shifting (outside the fence).

On May 11, 2023, the EPA issued proposed replacement rules to establish New Source Performance Standard ("NSPS"). These rules will regulate CO_2 emissions from both existing coal-fired EGUs and from natural gas and oil-fired EGUs. For coal-fired EGUs, the rules establish limits based on four operating subcategories and set BSER for each. BSER for each subcategory is based on permanent closure date and capacity factor of the unit, with increasingly stricter requirements for longer and more frequently run units. BSER begins with co-firing natural gas in the interim and eventually becomes carbon capture and sequestration ("CCS") by January 1, 2040. For natural gas and oil-fired EGUs greater than 300 MW with an annual capacity factor above 50%, BSER is set at either CCS by January 1, 2035, or a phase-in of hydrogen co-fire to 96% by volume by January 1, 2038.

On October 23, 2015, the EPA finalized the NSPS for CO_2 emissions from new, reconstructed, and modified power plants, setting BSER for natural gas-fired and coal-fired EGUs. This rule required CCS for coal-fired EGUs, effectively ending new construction of these units. On December 6, 2018, the EPA signed a proposed revision to the rule to set BSER for coal-fired EGUs to most efficient demonstrated steam cycle in combination with best operating practices, and removed the requirement for CCS. On May 11, 2023, the EPA issued a proposed replacement rule to regulate modified coal-fired EGUs. BSER for these units is proposed to be CCS. The EPA issued a separate proposed rule to regulate new and reconstructed combustion turbines. The rule establishes limits based on three operating subcategories based on capacity factor, with increasingly stricter emission limits for units that operate more frequently. BSER for intermediate and base load subcategories is either CCS or co-firing with hydrogen.

On April 4, 2023, the EPA proposed revisions to the Mercury and Air Toxics Standard (MATS), specifically related to the 2020 residual risk and technology review of this regulation conducted by the Agency. The EPA is currently considering tightening of this standard based on findings of this review. The EPA described these actions as a "non-rulemaking" intended to collect public input in advance of the EPA's commencement of a formal rulemaking process. The Authority cannot currently predict the outcome or future scope, timing, and costs associated with any CO_2 emissions requirements or MATS revisions.

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.

On the federal level, the EPA has announced its intention to implement a national program to evaluate and regulate a category of organic contaminants known as per- and polyfluoroalkyl substances ("PFAS"). The Authority does not anticipate significant implications for its power-related facilities but does anticipate new requirements for its Regional Water Systems because the first new requirements appear to be related to drinking water. Specifically, the Strategic Roadmap 2021-2024 announced by the EPA on October 18, 2021 states that public water systems will be required to participate in a nationwide monitoring program for PFAS in drinking water during a 12-month period sometime between the beginning of 2023 and the end of 2025. The EPA issued a final rule on December 27, 2021 for additional monitoring of public water systems that require monitoring of such systems for 29 PFAS as unregulated contaminants. On March 14, 2023, the EPA announced a proposed rule to establish national drinking water standards for six PFAS known to occur in drinking water. A final rule is expected in 2024. The Authority will comply with any applicable new standards that are issued.

In addition, the EPA's Revised Lead and Copper Rule (86 FR 4198) became effective on December 16, 2021, with a compliance date of October 16, 2024. This rule is expected to have only a minimal impact on the Authority's Regional Water Systems as the Authority's transmission system is completely constructed from cement lined ductile iron pipe. Changes in requirements for monitoring frequency, corrosion control treatment, and sampling procedure will be the primary effects to the Regional Water Systems. The Cross Generating Station includes a Non-Transient Non-Community Water System and is required to conduct an inventory of on-site drinking water pipes.

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 endeavors to operate in compliance with these permits.

The EPA issued their final rule regarding Section 316(b) of the CWA on August 15, 2014. The rule establishes requirements for cooling water intake structures ("CWISs") at existing facilities. Section 316(b) of the CWA requires that the location, design, construction, and capacity of CWISs reflect the best technology available (BTA) for minimizing adverse environmental impacts. The Authority will continue to work with the regulatory agencies on implementation as required. The Authority believes compliance costs are not significant.

The EPA regulates oil spills prevention and preparedness under the CWA, Spill Prevention Control and Countermeasures ("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. In addition to the SPCC requirements, the Myrtle Beach and Hilton Head Gas Turbine sites are subject to 40 CFR 112.20 and 112.21 requirements for Facility Response Plans (FRP).

A revision to the NPDES Steam Electric Effluent Limitation Guidelines ("ELG") rule became effective on November 1, 2020.

On October 13, 2020, the EPA published a revised ELG rule with lower mercury limits for Flue Gas Desulfurization ("FGD") wastewater along with some revisions related to bottom ash transport water. The 2020 rule also established a number of new subcategories. Beyond the standard best available technology (BAT) compliance option, subcategories potentially applicable for the Authority include those for retiring units and for facilities opting to comply via the voluntary incentive program (VIP) – each of these two alternate subcategories allow for an 8-year compliance schedule. Construction on many of the treatment systems and equipment required to comply with the 2020 rule is complete and the Authority expects the remaining cost of compliance at Cross and Winyah to be approximately $155 million and $150 million, respectively, for FGD wastewater treatment construction, using the rule's BAT approach (physical-chemical and biological treatment).
Previously, the Authority's board voted to retire Winyah and utilize the retirement exemption in the ELG rule; however on February 8, 2023, the Authority and Central Electric Cooperative signed a Memorandum of Understanding documenting an agreement to pursue the BAT technology as the primary compliance strategy for Winyah.

ELG requirements under the 2020 rule, along with any new state-defined limits, will be included in the final revised NPDES discharge permits that are currently being finalized by DHEC. While not final, draft permits for Cross and Winyah were put on public notice by DHEC in November and December 2023, respectively.

These draft permits contain schedules for implementation of FGD wastewater treatment at Cross and Winyah. The ability to switch to other compliance strategies for FGD wastewater is also not precluded. The Authority has submitted a notice of planned participation ("NOPP") for the voluntary incentive program (VIP) for Cross, based on treatment via membrane technology, and has requested parallel compliance paths in its permit.

This is intended to allow the BAT approach at Cross, while allowing the option to change to the VIP approach if that develops as a preferred option. The Authority also submitted a NOPP for retirement at Winyah, which would allow an automatic transfer to the VIP option under the rule; in addition, the Authority has requested that language addressing automatic transfer to the VIP option be included in the final permit.

While the 2020 rule remains in force at this time, the EPA announced a new rulemaking initiative in the Federal Register ("FR") on August 3, 2021, stating its intention to reevaluate FGD wastewater and bottom ash transport water limits and compliance alternatives in a new rule. The FR statement announced the EPA's intention that permittees and state permitting authorities follow the 2020 rule until the new rule is published. EPA released a pre-publication version of a new proposed rule on March 8, 2023, which, if it were to be finalized without alteration, would require aggressive new treatment requirements similar to the 2020 rule's VIP subcategory. Santee Cooper is thoroughly analyzing this proposed rule and will take action to comply with the final rule, which is currently anticipated in April 2024. At this time, it is not possible to identify a method of compliance or associated costs with the pending new rulemaking.

On June 9, 2021, the Army Corps of Engineers and EPA announced its intention to initiate a new rulemaking process that "restores the protections in place" prior to the 2015 Waters of the U.S. ("WOTUS") rule and to develop a more durable definition. The final rule published in the Federal Register on January 18, 2023 establishes a broader scope of jurisdiction under the Clean Water Act, resulting in more jurisdictional wetlands and fewer non-jurisdictional wetlands; the waste treatment exclusion was maintained. In addition to these regulatory actions, on May 25, 2023 the U.S. Supreme Court issued a decision on a lower court ruling (Sackett v. EPA) that limits CWA jurisdiction. The court's opinion essentially adopts the *Rapanos et al. v The United States* plurality's "continuous surface connection" standard authored by Justice Scalia, rejecting the "significant nexus" test described in Justice Kennedy's concurring opinion in *Rapanos*. On September 8, 2023, EPA published a new rule codifying the Sackett decision; however, in South Carolina the pre-2015 regulatory regime is in place due to ongoing litigation challenging the 2023 WOTUS Rule. At this time, it is not possible to determine the outcome of these various regulatory actions or to predict the changes that may occur as a result of the continued litigation. The primary risk to the Authority is that obtaining wetlands and WOTUS-related permits may require additional time and cost for new construction.

Hazardous and Non-Hazardous Substances, Solid Wastes and Coal Combustion Byproducts -

Under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("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. 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. CERCLA provides for the reporting requirements to cover the release of hazardous substances into the environment.

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's corporate policy titled Solid, Universal and Hazardous Waste (Policy Number 2-42-02) and the Corporate Waste Management Guidance Document provide guidance for the proper management and monitoring of solid, universal, and hazardous waste for environmental and regulatory compliance. 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.
The Authority's corporate policy titled PCB Management (Policy Number 5-23-04) and the PCB Management Plan provide guidance for the proper management and monitoring of PCBs for environmental and regulatory compliance.

The Solid Waste Disposal Act and Energy Policy Act give the EPA authority to regulate Underground Storage Tanks ("USTs"). EPA regulations concerning USTs are contained in 40 CFR Parts 280-282. DHEC was granted state program approval in 2002 and regulates USTs under R. 61-92, Part 280. This regulation provides requirements for the design, installation, operation, closure, release detection, reporting and corrective action and financial responsibility. The Authority's corporate policy titled Underground Storage Tanks (Policy Number 2-11-03) provides guidance for the proper management and monitoring of USTs for environmental and regulatory compliance.

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 CCR Rule establishing comprehensive requirements for the management and disposal of CCRs. The rule regulates CCRs as a RCRA Subtitle D, nonhazardous waste and had an effective date of October 19, 2015. The Authority continues to comply with the CCR Rule through groundwater monitoring, assessment of corrective measures and internet postings of CCR Rule reports. Long-term compliance plans to address groundwater include pond closures and utilization of Class 3 landfills at the Cross and Winyah Generating Stations for disposal of CCRs. Beneficial use of ash and gypsum results in removal of CCRs from ponds to support closure and fewer CCRs being disposed of in the on-site landfills. The Class 3 landfill at Winyah Generating Station has been in operation since November 2018 with the latest and last expansion receiving approval to operate from DHEC in December 2022. The Cross Generating Station's Class 3 landfill continues in operation, and an expansion is currently under construction. These two Class 3 landfills are subject to the CCR Rule. The surface impoundments subject to the CCR Rule are located at the Cross and Winyah Generating Stations. These CCR impoundments have triggered closure because they are unlined and do not meet the aquifer location standard. Additionally, a subset of these CCR impoundments do not meet the groundwater protection standards for one or more constituents and are thus in a Corrective Action program. As of the April 11, 2021 CCR rule deadline, all ponds subject to the CCR Rule are no longer receiving any CCR or non-CCR waste streams.

Other CCR rulemakings are pending and will be monitored to address any requirements that impact the Authority. The EPA has issued a proposed rulemaking regarding regulating legacy impoundments and the final rule is expected in April 2024. Under this rulemaking, other ponds could become subject to the CCR Rule, including the Jefferies Generating Station ash pond and possibly the Grainger Generating Station ash ponds, even though the Grainger ash ponds have completed closure in accordance with DHEC's requirements. Additional CCR management units may also become subject to this rule. Other rulemakings which are expected to be issued in the near future include a Federal CCR Permit Program (expected March 2026) with procedures for CCR units to obtain permits in non-participating states, which currently includes South Carolina, and an additional closure option for units that are closing by removal of CCR but cannot complete groundwater corrective action within the rule's prescribed closure timeframes (expected October 2024). The CCR regulations and the EPA's interpretation of them have changed frequently and are expected to change in the ways described above. The Authority cannot predict other changes that the EPA may impose or the impacts upon the Authority's operations and financial results of these regulatory and interpretive changes until they are finalized and their impacts upon the Authority can be evaluated.

Closure plans for the Jefferies Generating Station Ash Pond and for the Winyah West Ash Pond have been approved by DHEC and closure is in progress, with regulatory deadlines of 2030. These ponds are not currently subject to the CCR Rule. However, as noted above, pending CCR rulemakings could regulate these impoundments. The Cross Bottom Ash Pond and the remaining ponds at the Winyah Generating Station (A Ash Pond, B Ash Pond, South Ash Pond, and Units 3 & 4 Slurry Pond) are subject to both the CCR Rule's closure requirements and to DHEC closure regulations. Closure is in progress on all ponds and plans are being developed and implemented to facilitate closure of these remaining ponds by the deadlines established by the state and by the CCR Rule with applicable extensions if necessary. The ponds will be closed through excavation and beneficial use of materials or through disposal in the industrial Class 3 solid waste landfills on-site at Cross and Winyah. For ponds subject to corrective action under the CCR Rule, closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards. Four ponds (Winyah Slurry Pond 2, Grainger Ash Pond 1, Grainger Ash Pond 2, and the Cross Gypsum Pond) have already completed closure in accordance with DHEC's requirements. Pond closure activities are expected to continue at least through 2031 and estimates of remaining costs are projected to be approximately $197 million between 2024 and 2031. This amount does not include possible groundwater corrective action for the Cross Gypsum Pond being conducted under the CCR Rule, for which additional costs, if any, are not yet known. These costs are also part of the asset retirement obligation.

Wildlife – The Authority's operations have the potential to impact threatened and endangered species, birds, and other wildlife protected by the Endangered Species Act ("ESA"), Migratory Bird Treaty Act ("MBTA"), National Environmental Policy Act ("NEPA"), and additional state and federal requirements. Penalties for violations can be substantial and include criminal liability. The Authority endeavors to ensure that its facilities, operations, and projects comply with all applicable wildlife protection requirements.

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.

On December 31, 2020, the Authority was notified by DHEC that the Authority was required to submit a Site-Specific Work Plan ("SSWP") for an Initial Ground Water Assessment ("IGWA") under the South Carolina Pollution Control Act (SC Code Ann. § 48-1-50(6), § 48-1-50(20), and § 48-1-50(21)) at the Hidden Cove Marina, a property within the Authority's FERC project boundaries that is currently occupied by a commercial lessee. An underground pipe on the property was damaged by employees of a telecommunications company during installation of underground wiring and an estimated 800 gallons of gasoline leaked into the surrounding soil. DHEC informed the Authority that DHEC considers the Authority responsible for any necessary remediation activities, although the Authority reached a cost sharing agreement with the telecommunications company and lessee. After the IGWA results were received and indicated groundwater contamination, DHEC requested a Tier II assessment SSWP for additional soil and groundwater sampling. The Tier II results were submitted to DHEC on September 14, 2021. Subsequent activity resulted in DHEC approving an Excavation Corrective Action Plan and a Well Installation Plan on November 18, 2021. The Corrective Action Plan activities were completed in 2023 and the Authority received a Conditional No Further Action decision from DHEC on July 18, 2023.

A separate property exists within the Authority's FERC project boundaries that is currently occupied by a commercial lessee, Packs Landing Marina. As part of a proposed South Carolina Department of Transportation (SCDOT) right-of-way project, ARM Environmental reported a release at Packs Landing Marina on May 20, 2002 by submitting a Limited Phase II Subsurface Assessment for SCDOT Project #99-188D. The assessment found that a UST had been removed, there was an AST with dispensers, and subsurface hydrocarbon contamination (both soil and groundwater) was identified. Based on that information, DHEC began working with the lessee to get the contamination addressed on this site, identified as Site ID# 01935. DHEC was not successful in getting the contamination addressed with the lessee and contacted the Authority as the owner of the property. On February 26, 2014, the Authority was notified by DHEC that based on the groundwater monitoring report received August 29, 2013, the submittal of a Tier II Assessment Plan was required under the South Carolina Pollution Control Act (SC Code Ann. § 48-1-50(6), § 48-1-50(20), and § 48-1-50(21). The Authority agreed to monitor the progress of the environmental work and assist with financing the cost of environmental assessment for the lessee. Work has been conducted on the site since 2013 through DHEC approved workplans. On March 17, 2021, DHEC issued a directive to Packs Landing Marina for a SSWP to conduct additional testing for creosote found in results for the site, and the Authority entered into a Responsible Party Voluntary Cleanup Contract ("VCC") with DHEC on March 18, 2022. The VCC addresses the Authority and DHEC's cooperative plan for remediation of the creosote on the property. The Authority has submitted its Work Plan for the VCC process, which DHEC has accepted, and work has begun under that agreement, while the hydrocarbon component continues independent of the VCC.

The Authority's asset retirement obligation liabilities for ash ponds recorded for the years ended December 31, 2023 and 2022 were $154.8 million and $178.6 million, respectively.

FERC Hydroelectric License - The Authority operates the Santee Cooper Project (FERC P-199), including its Jefferies Hydro Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam on the Santee River, which are major parts of the Authority's integrated hydroelectric complex, under a license issued by the FERC pursuant to the Federal Power Act ("FPA"). The project recently completed a multi-decade relicensing effort and was issued a 50-year license order by the FERC on January 20, 2023. The license is effective through January 1, 2073.

The Authority initiated license order compliance efforts upon receipt of the new license, including creation and implementation of various threatened and endangered species protection plans, a nuisance and invasive aquatic plant management plan, an operations and flow monitoring plan, a recreation management plan, a historic properties management plan, study plans focused on diadromous fish species, and plans for capital upgrades required to safely pass the required increased minimum flows into the Santee River at the Santee Dam. Total implementation costs for new requirements associated with the terms and conditions of the license order are estimated to be between $84 million and $179 million. The Authority has recorded approximately $350,000 in capital assets for the FERC Hydroelectric license through December 31, 2023.

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 the Authority's financial condition, or the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution. The Authority is vigorously defending any liability in all pending litigation; however, the cases may be subject to trial by a jury, judge, or arbitrator(s), which serves as the final trial trier of facts and awards. Alternatively, the Authority may decide to enter settlement negotiations to resolve such disputes. The Authority is unable to predict the outcome of the matters described below. Adverse decisions or determinations could delay or impede the Authority's operation or construction of its existing or planned projects, and/or require the Authority to incur substantial additional costs. Such results could materially adversely affect the Authority's revenues and, in turn, the Authority's ability to pay debt service on its bonds.

Recently Settled Litigation Matters

Jessica S. Cook et al. v. the Authority, the Authority's Board of Directors (certain former and current Directors named), SCE&G, SCANA Corporation, SCANA Services, Inc., Palmetto Elec. Coop., & Central Elec. Pwr. Coop.

Plaintiffs filed this putative class action in the Hampton County Court of Common Pleas on August 22, 2017, in connection with the Authority's decision to suspend construction of Summer Nuclear Units 2 and 3. Numerous amended complaints, responsive pleadings, and cross-claims were filed, up to and including a Fifth Amended Complaint. Plaintiffs' claims generally sought on behalf of a class of members the repayment of amounts paid by ratepayers attributable to Summer Nuclear Units 2 and 3 under statutory, contract, tort, and equitable theories. Plaintiffs also asserted claims against Palmetto, Central, SCANA, SCE&G, and SCANA Services. As detailed below, the case was resolved at mediation and an Amended Order Approving Settlement was entered on July 31, 2020, which approved the terms of the settlement reached by the parties resolving this matter and *Timothy Glibowski et al. v. SCANA, SCE&G, the Authority, et al.*

In addition to resolving Cook, the Cook Settlement Agreement resolved this putative class action filed in the Beaufort Division of the United States District Court for the District of South Carolina on January 31, 2018. The Plaintiffs filed an amended complaint on April 23, 2018 adding the Authority as a defendant. As against the Authority, Plaintiffs' claims arose from decisions to suspend construction of Summer Nuclear Units 2 and 3. The action was brought on behalf of a putative class of persons comprised of SCANA customers, Authority customers, and Central customers who paid advance charges for costs associated with the construction of the units from 2007 to 2019. Amended pleadings were filed, up to and including a Third Amended Complaint filed on July 30, 2019. The Third Amended Complaint asserted RICO and RICO Conspiracy claims against SCANA, SCE&G, SCANA's officers, the Authority and three now retired employees of the Authority as well as a takings claim against the Authority. Plaintiffs sought actual damages, treble damages under RICO, and attorneys' fees. As the claims in this matter were fully resolved as part of the Cook matter described above, the Court entered an order dismissing this matter on May 15, 2020.

The Cook Settlement Agreement generally provides for the dismissal and the release of all claims belonging to the class members against the Defendants, including those against the Authority. The class members are defined as all customers of the Authority that paid utility bills, during the time period from January 1, 2007 to January 31, 2020, with rates that were calculated in part to pay costs of Summer Nuclear Units 2 and 3 (the "Class Members"). In exchange for dismissal and release of the claims, SCE&G (n/k/a) DESC and the Authority agreed to make certain payments to a Common Benefit Fund (the "Fund") to be paid to Class Members. The Authority's portion of the payments to the Fund is $200 million, which were paid in three annual installments in the third quarters of 2020, 2021, and 2022, in the amount of $65 million, $65 million, and $70 million, respectively. In addition, the Authority agreed to a freeze on its rates consistent with rates projected in the Reform Plan beginning in 2020 through the end of 2024, subject to certain exceptions like costs arising from named storm events or changes in the law. The description here in this paragraph of the Cook Settlement Agreement is a general summary of the major provisions. A copy of the agreement can be found at http://www.santeecooperclassaction.com/Content/Documents/Settlement%20Agreement.pdf.

The Authority submits a compliance report to the Court annually through 2030.

Pending Litigation

(a) *Central Agreement Audit Dispute*

Following an annual audit of the Authority's records as permitted under the Central Agreement, Central has taken issue with the Authority's treatment of the Summer Nuclear Units 2 and 3 associated regulatory asset under the Central Agreement's cost of service model. Central's treatment of the regulatory asset, if applied, would result in the return to Central of over $76 million for fiscal years 2017, 2018, 2019, and January – July 2020 and a reduction in future contributions from Central in a yet undetermined amount. The Authority responded to Central, noting its disagreement with Central's position. The parties will proceed with determining a means for resolving the dispute.

(b) *Central Arbitration Notice*

On September 23, 2021, Central tendered a Notice of Arbitration, as permitted under the Central Agreement, presenting questions related to the Authority's accounting for gypsum expenses and revenues in conjunction with the Authority's contract with American Gypsum. The Authority submitted a response denying the allegations on October 15, 2021. A full arbitration Tribunal was selected, but the parties reached a tentative agreement contingent on future events. If the agreement is not finalized or the contingent events do not occur, it is likely an arbitration will occur. Court proceedings may follow the Tribunal's decision pursuant to the terms of the Central Agreement.

(c) *South Carolina Public Service Authority v. U.S. Army Corps of Engineers (COE)*

The Authority filed a claim on October 2, 2015 against the COE seeking a determination that the Rediversion Contract between the Authority and the COE does not require the Authority to credit the COE for a capacity value surcharge. The Rediversion Contract governs the operation of the St. Stephen Hydro Plant and the obligations of the parties related to the Plant's operations. The COE denied the claim and asserted the Authority was required to pay the COE based on a calculation which is in dispute. The Authority appealed the decision to the Armed Services Board of Contract Appeals ("ASBCA") and the COE counterclaimed. The parties asked the ASBCA to determine the rights under the contract.

On July 22, 2020, the ASBCA denied the Authority's appeals and remanded to the parties to negotiate the value of the additional capacity for the final 20 years of the contract performance period based on the contract. Negotiations are ongoing.

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 System ("SCRS") and serves as a co-trustee of the Systems in conducting that review.

PEBA issues an Annual Comprehensive Financial Report ("ACFR") containing financial statements and required supplementary information for the Systems' Pension Trust Funds. The ACFR 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.

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, (9.00 percent employee cost and 18.41 percent employer cost); however, under the State ORP, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 13.41 percent is contributed to the SCRS. As of December 31, 2023, the Authority had 111 employees participating in the State ORP and consequently the related payments are not material.

Effective July 1, 2017, the Retirement System Funding and Administration Act of 2017 (the "Act") increased employer retirement contribution rates by 2 percent to 13.56 percent for SCRS. The employer contribution rate for the State ORP was increased to 13.56 percent, with 5 percent of the employer contribution being remitted directly to the participant's State ORP investment provider. The employer rate will continue to increase annually by 1 percent through July 1, 2023, with the ultimate employer rate reaching 18.41 percent. Employee rates for SCRS and the State ORP increased to and are capped at 9 percent. Employer and employee contribution rates may be decreased in equal amounts once the system is 85 percent funded. The employee contribution rate may not be less than ½ of the normal cost for the system. The Act also reduced the funding period for unfunded liabilities from 30 to 20 years over the next 10 years as well as lowered the current assumed annual rate of return from 7.5 percent to 7.25 percent. The assumed annual rate of return expired July 1, 2021 and will every four years thereafter. PEBA must propose an annual rate of return every four years, which will become effective if the General Assembly fails to enact a rate of return.

Contributions - All employees are required by State statute to contribute to the SCRS at the prevailing rate, currently 9.00 percent. The Authority contributed 18.41 percent of the total payroll for SCRS retirement. For 2023, the Authority also contributed an additional 0.15 percent of total payroll for group life.

Liabilities, Expense and Deferred Outflows (Inflows) of Resources Related to Pensions - At December 31, 2023, the Authority reported a liability of $302.5 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, 2023 and determined by an actuarial valuation as of July 1, 2022. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $25.1 million paid to SCRS for the year ended June 30, 2023 relative to the actual contributions of $2.1 billion from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2023 and 2022 are as follows:

	June 30, 2023	June 30, 2022
Authority's proportion of the net pension liability (%)	**1.19%**	1.21%
Authority's proportion of the net pension liability (millions)	**$290.2**	$295.2
Authority's covered payroll (millions)	**$143.9**	$148.9
Authority's proportion of the net pension liability as a percentage of its covered payroll	**202%**	198%
Plan fiduciary net position as a percentage of the total pension liability	**58.60%**	57.10%

For the year ended December 31, 2023, the Authority recognized a pension expense of $19.4 million, the Authority's proportionate share of the total pension expense. At December 31, 2023, 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	**$ 5,077**	**$ 817**
Changes of assumptions	**4,455**	**0**
Net difference between projected and actual earnings on pension plan investments	**0**	**398**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**365**	**10,845**
Authority's contributions subsequent to the measurement date	**12,706**	**0**
Total	**$ 22,603**	**$ 12,060**

The Authority reported $12.7 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, 2024. 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, 2023. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2023, was 3.678 years for SCRS.

Year Ending December 31:	
	(Thousands)
2024	**$ 140**
2025	**(9,927)**
2026	**7,795**
2027	**(171)**
Total	**$ (2,163)**

For the year ended December 31, 2022, the Authority recognized a pension expense of $12.4 million, the Authority's proportionate share of the total pension expense. At December 31, 2022, 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	$ 2,576	$ 1,309
Changes of assumptions	9,481	0
Net difference between projected and actual earnings on pension plan investments	43,528	43,071
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	771	16,455
Authority's contributions subsequent to the measurement date	11,346	0
Total	$ 67,702	$ 60,835

The Authority reported $11.3 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, 2023. 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, 2022. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2022, was 3.767 years for SCRS.

Year Ending December 31:	
	(Thousands)
2023	$ (1,630)
2024	(170)
2025	(10,395)
2026	7,717
Total	$ (4,478)

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, 2023:

-	**Measurement Date**	**June 30, 2023**
-	**Valuation Date**	**July 1, 2022**
-	**Expected Return on Investments**	**7.00%**
-	**Inflation**	**2.25%**
-	**Future Salary Increases**	**3.00% plus step-rate increases for members with less than 21 years of service**
-	**Mortality Assumption**	**2020 Mortality Table projected at SCALE UMP from year 2020**
		2020 Males multiplied by 97%. Females multiplied by 107%

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2022:

-	Measurement Date	June 30, 2022
-	Valuation Date	July 1, 2021
-	Expected Return on Investments	7.25%
-	Inflation	2.25%
-	Future Salary Increases	3.00% to 12.50% (varies by service)
-	Mortality Assumption	2016 Mortality Table set back projected at SCALE AA from 2016 Males multiplied by 100%. Females multiplied by 111%

Discount Rate - The discount used to measure the total pension liability was 7.00 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, 2023, the long-term expected rate of return on pension plan investments is based upon 20-year capital market assumptions. The long-term expected rates of return represent assumptions developed using an arithmetic building block approach primarily based on consensus expectations and market-based inputs. Expected returns are net of investment fees. The expected returns, along with the expected inflation rate, form the basis for the target allocation adopted at the beginning of the 2023 fiscal year. The long-term expected rate of return is produced by weighting the expected future real rates of return by the target allocation percentage and adding expected inflation and is summarized in the table on the following page.
For actuarial purposes, the 7.00 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 2.25 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long-Term Expected Portfolio Real Rate of Return
Global Equity			
Public Equity	**46.00%**	**6.62%**	**3.04%**
Private Equity	**9.00%**	**10.91%**	**0.98%**
Real Assets			
Real Estate	**9.00%**	**6.41%**	**0.58%**
Infrastructure	**3.00%**	**6.62%**	**0.20%**
Diversified Credit			
Bonds	**26.00%**	**0.31%**	**0.08%**
Private Debt	**7.00%**	**6.16%**	**0.43%**
Total Expected Real Return	**100.0%**		**5.31%**
Inflation for Actuarial Purposes			**2.25%**
Total Expected Nominal Return			**7.56%**

For the measurement date as of June 30, 2022, the long-term expected rate of return on pension plan investments is based upon 20-year capital market assumptions. The long-term expected rates of return represent assumptions developed using an arithmetic building block approach primarily based on consensus expectations and market-based inputs. Expected returns are net of investment fees. The expected returns, along with the expected inflation rate, form the basis for the target allocation adopted at the beginning of the 2022 fiscal year. The long-term expected rate of return is produced by weighting the expected future real rates of return by the target allocation percentage and adding expected inflation and is summarized in the table on the following page. For actuarial purposes, the 7.00 percent assumed annual investment rate of return (as prescribed by South Carolina 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 2.25 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long-Term Expected Portfolio Real Rate of Return
Global Equity			
Public Equity	46.00%	6.79%	3.12%
Private Equity	9.00%	8.75%	0.79%
Real Assets			
Real Estate	9.00%	4.12%	0.37%
Infrastructure	3.00%	5.88%	0.18%
Diversified Credit			
Bonds	26.00%	(0.35%)	0.09%
Private Debt	7.00%	6.00%	0.42%
Total Expected Real Return	100.0%		4.79%
Inflation for Actuarial Purposes			2.25%
Total Expected Nominal Return			7.04%

Sensitivity Analysis - For the measurement date as of June 30, 2023, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.00% as well as SERP discount rates of 4.25% for both the pre-2007 and 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	**$ 388,018**	**$ 302,480**	**$ 231,335**

For the measurement date as of June 30, 2021, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.00% as well as SERP discount rates of 2.25% for both the pre-2007 and 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	$ 392,700	$ 308,585	$ 238,582

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. Effective February 23, 2018, entry into the plan is closed and no employee shall become a participant on or after this date. At December 31, 2023, the Authority reported an asset of $3.6 million and a liability of $12.5 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	$ 5	$ 170
Changes of assumptions	0	0
Net difference between projected and actual earnings on pension plan investments	811	0
Authority's contributions subsequent to the measurement date	193	0
Total	**$ 1,009**	**$ 170**

The Authority reported $193,000 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, 2024. 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, 2023.

Year Ending December 31:	
	(Thousands)
2024	$ 12
2025	239
2026	384
2027	11
2028	0
Total	**$ 646**

At December 31, 2022, the Authority reported an asset of $3.5 million and a liability of $13.3 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	$ 14	$ 371
Changes of assumptions	5	0
Net difference between projected and actual earnings on pension plan investments	1,492	642
Authority's contributions subsequent to the measurement date	188	0
Total	$ 1,699	$ 1,013

The Authority reported $188,000 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, 2023. 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, 2022.

Year Ending December 31:		
	(Thousands)	
2023	$	(122)
2024		19
2025		227
2026		373
2027		0
Total	$	497

Summer Nuclear Unit 1 Retirement - The Authority and DESC are parties to a joint ownership agreement for Summer Nuclear Unit 1 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, 2023, and 2022, the Authority had a pension liability of $8.3 million and $6.7 million, respectively. The Authority has a regulatory asset balance of approximately $10.5 million and $5.9 million for the unfunded portion of pension benefits at December 31, 2023 and 2022, respectively. Additional information may be obtained by reference to DESC. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2023.

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 greater than 5 years but less than 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 1,169 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.

As of the measurement date, June 30, 2023, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	1,192
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	0
Active Plan Members	1,501
Total Plan Members	**2,693**

As of the measurement date, June 30, 2022, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	1,146
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	0
Active Plan Members	1,509
Total Plan Members	2,655

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. In 2018 with the implementation of GASB 75, the Authority established a formal funding plan and elected to fund the OPEB obligation over a 30-year closed period. This method of funding results in a lower OPEB liability and established a method for amortizing the regulatory asset as funding occurs.

Net OPEB Liability - The components of the net OPEB liability at June 30, 2023 were as follows:

		(Thousands)
Total OPEB Liability	$	247,327
Plan fiduciary net position		97,290
Authority's net OPEB liability	$	150,037
Plan fiduciary net position as a percentage of the total OPEB liability		39.34%

The components of the net OPEB liability at June 30, 2022 were as follows:

		(Thousands)
Total OPEB Liability	$	299,066
Plan fiduciary net position		95,249
Authority's net OPEB liability	$	203,817
Plan fiduciary net position as a percentage of the total OPEB liability		31.85%

Actuarial Methods and Assumptions - The total OPEB liability was determined by an actuarial valuation as of June 30, 2023 using the following actuarial assumptions, applied to all periods included in the measurement, unless otherwise specified.

Actuarial Methods and Assumptions	
Actuarial Cost Method	Individual Entry-Age
Amortization Method	Level dollar
Amortization Period	Closed period; 24 years remaining as of the beginning of FYE23
Asset Valuation	Market Value
Investment Rate of Return	4.00%, net of investment expenses, including inflation
Inflation	2.25%
Salary Increases	3.00% to 9.50%, including inflation
Demographic Assumptions	Based on the experience study covering the five year period ending June 30, 2019 as conducted for the South Carolina Retirement Systems (SCRS)
Mortality	For healthy retirees, the gender-distinct South Carolina Retirees 2020 Mortality Tables are used with fully generational mortality projections using 80% of Scale UMP to account for future mortality improvements and adjusted with multipliers based on plan experience.
Participation Rates	Rates of 95% for fully funded retirees, 60% for partially funded retirees, and 20% for retirees not eligible for any explicit subsidy.
Healthcare Cost Trend Rates	Initial rate of 5.30% declining to an ultimate rate of 3.7% after 15 years.

Investments - The investments of the Authority must follow the general guidelines set by the Enabling Legislation. The Authority is required to invest without limitation its revenues in obligations the interest and principal of which are guaranteed or are fully secured by contracts with the United States of America; in obligations of any agency, instrumentality or corporation which has been or may hereafter be created by or pursuant to an act of Congress; direct and general obligations of the State of South Carolina; and certificates of deposit issued by any bank, trust company or national banking association which do business in South Carolina.

Asset Class	Target Allocation	Long-Term Expected Real Rate of Return
Cash	2.40%	0.12%
Fixed Income	97.60%	4.86%
Total Blended Average	**100.0%**	**4.98%**

Asset Allocation at June 30, 2023

The rate of return for 2023 on the Trust was 2.09%.

Discount rate. A Single Discount Rate of 4.00% was used to measure the total OPEB liability. The expected rate of return on OPEB plan investments is 4.00%. The municipal bond rate is 3.86% (based on the daily rate closest to but not later than the measurement date of the Fidelity “20-Year Municipal GO AA Index”); and the resulting Single Discount Rate is 4.00%.

Schedule of Changes in Net OPEB Liability and Related Ratios
Fiscal Year Ended December 31, 2023

Measurement period ending June 30	**2023**	2022
	(Thousands)	
Service Cost	**$ 6,052**	$ 7,098
Interest on the total OPEB liability	**8,910**	8,755
Difference between expected and actual experience	**(40,154)**	177
Changes of Assumptions	**(16,422)**	(260)
Benefit payments	**(10,125)**	(10,013)
Net change in total OPEB liability	**(51,739)**	5,757
Total OPEB liability - beginning	**299,066**	293,309
Total OPEB liability - ending (a)	**$ 247,327**	$ 299,066
Plan fiduciary net position		
Employer contributions	**$ 19,243**	$ 20,283
OPEB plan net investment income	**(6,923)**	(20,631)
Benefit payments	**(10,125)**	(10,013)
OPEB plan administrative expense	**(154)**	(171)
Net change in plan fiduciary net position	**2,041**	(10,532)
Plan fiduciary net position - beginning	**95,249**	105,781
Plan fiduciary net position - ending (b)	**$ 97,290**	$ 95,249
Net OPEB liability - ending (a) - (b)	**$ 150,037**	$ 203,817
Plan fiduciary net position as a percentage of total OPEB liability	**39.34%**	31.85%
Covered-employee payroll (dollars)	**$159,216,510**	$146,304,252
Net OPEB liability as a percentage of covered-employee payroll	**94.23 %**	139.31 %

Sensitivity of the net OPEB liability to changes in the discount rate - The following presents the net OPEB liability of the Authority calculated using the Authority's discount rate of 4.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2023.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Net OPEB liability	$ 189,360	$ 150,037	$ 118,262

The following presents the net OPEB liability of the Authority calculated using the Authority's discount rate of 3.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate as of June 30, 2022.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Net OPEB liability	$ 254,294	$ 203,817	$ 163,311

Sensitivity of the net OPEB liability to changes in the healthcare cost trend rates **-** The following presents the net OPEB liability of the Authority calculated using the assumed healthcare trend rates and for what the Authority's net OPEB liability would be if it were calculated using a trend rate that is 1.00% lower or 1.00% higher than the current trend rate as of June 30, 2023.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 112,361	$ 150,037	$ 198,229

The following presents the net OPEB liability of the Authority calculated using the assumed healthcare trend rates and for what the Authority's net OPEB liability would be if it were calculated using a trend rate that is 1.00% lower or 1.00% higher than the current trend rate as of June 30, 2022.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 152,719	$ 203,817	$ 270,319

OPEB Expense and Deferred Outflows (Inflows) of Resources Related to OPEB **-** For the year ended December 31, 2023, the Authority recognized OPEB expense of $15.9 million. At December 31, 2023, the Authority reported deferred outflows (inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	**$ 4,579**	**$ 37,517**
Changes of assumptions	**14,877**	**15,181**
Net difference between projected and actual earnings on OPEB plan investments	**23,900**	**0**
Authority's contributions subsequent to the measurement date	**12,652**	**0**
Total	**$ 56,008**	**$ 52,698**

The Authority reported $12.6 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net OPEB liability in the year ending December 31, 2024. Other amounts reported as deferred outflows (inflows) of resources will be recognized in OPEB expense in future years.

The following schedule reflects the amortization of the Authority's balance of remaining deferred outflows (inflows) of resources at December 31, 2023.

Year Ending December 31:	
	(Thousands)
2024	$ 4,251
2025	4,691
2026	(792)
2027	(5,396)
2028	(8,907)
Thereafter,	(3,190)
Total	$ (9,343)

For the year ended December 31, 2022, the Authority recognized OPEB expense of $23.9 million. At December 31, 2022, the Authority reported deferred outflows (inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 5,754	$ 5,564
Changes of assumptions	21,855	1,770
Net difference between projected and actual earnings on OPEB plan investments	20,817	0
Authority's contributions subsequent to the measurement date	9,113	0
Total	$ 57,539	$ 7,334

The Authority reported $9.1 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net OPEB liability in the year ending December 31, 2023. Other amounts reported as deferred outflows (inflows) of resources will be recognized in OPEB expense in future years.

The following schedule reflects the amortization of the Authority's balance of remaining deferred outflows (inflows) of resources at December 31, 2022.

Year Ending December 31:	
	(Thousands)
2023	$ 10,687
2024	11,166
2025	11,605
2026	6,123
2027	1,519
Thereafter,	(9)
Total	$ 41,091

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, 2023 and 2022 were both approximately $13.2 million and $12.8 million, respectively.

The Authority recorded a regulatory liability of approximately $2.9 million at December 31, 2023. Additional information may be obtained by reference to the DESC. Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2023.

Note 13 – Credit Risk and Major Customers

In 2023 and 2022, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:		2023		2022
		(Millions)		
Central	**$**	**1,050**	$	1,059

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, 2023 and 2022 was $2.4 million and $2.5 million, respectively.

Note 14 – Impact of Novel Coronavirus (COVID-19) Pandemic

In early 2023, FEMA announced the incident period for the COVID-19 pandemic would end on May 11, 2023. The Authority did not incur any costs associated with Protective Measures in 2023.

The Authority captured all costs associated with the Protective Measures incurred in 2022 and 2021. The amounts were approximately $900 thousand and $3.5 million, respectively.

The Authority continues to monitor the COVID-19 Pandemic and all costs associated with the global event for any financial impact but does not expect the costs associated with this event to have measurable long-term impact on its operations of the production and delivery of electricity to its customers. Through December 31, 2023, the Authority has been reimbursed $70,992 from FEMA for prior COVID-19 costs and has recognized a regulatory asset of approximately $9.5 million for unreimbursed COVID-19 costs (see Note 5- *Cook Settlement as to Rates*).

Note 15 – Cherokee Acquisition

On October 31, 2023, the Authority completed the purchase of Cherokee Cogeneration Partners LLC, including a natural gas-generating facility in Cherokee County for approximately $17 million. This facility added nearly 100 megawatts to the Authority's combined electric system. This facility has been operating since 1998 and is connected to an existing natural gas supply pipeline. The purchase was approved by the Public Service Commission in September 2023, and the land transaction was approved by the state's Joint Bond Review Committee in October 2023.

Note 16 – Subsequent Events

In January 2024, Santee Cooper executed a Precedent Agreement with the natural gas pipeline company, Transco, to be a pipeline capacity holder of the Southeast Supply Enhancement expansion project. This pipeline project has a target in service date of November 2027. The pipeline project stretches from the Mountain Valley Pipeline and Transco interconnect in Pittsylvania County, Virginia to Transco's delivery points in the southeastern US. Santee Cooper would utilize the added capacity of 80,000-MMBtu/day for the Rainey and Cherokee natural gas stations and potentially a new natural gas generating station. The project must be approved by FERC. Santee Cooper is responsible for it's proportionate share of project costs (incurred and committed to as of that date) if Santee Cooper terminates for any reason.

REQUIRED SUPPLEMENTAL FINANCIAL DATA (UNAUDITED):

Schedule of Proportionate Share of the Net Pension Liability
Required Supplementary Information

Years Ended in June 30,	**2023**	2022	2021	2020	2019	2018	2017	2016	2015	2014
Authority's proportion of the net pension liability (%)	**1.19%**	1.21%	1.28%	1.28%	1.35%	1.43%	1.43%	1.45%	1.44%	1.45%
Authority's proportion of the net pension liability (millions)	**$290.2**	$295.2	$278.9	$327.9	$309.7	$321.8	$323.1	$309.7	$273.6	$249.7
Authority's covered payroll (millions)	**$143.9**	$148.9	$152.7	$149.7	$151.1	$156.5	$153.7	$147.7	$140.7	$135.0
Authority's proportion of the net pension liability as a percentage of its covered payroll	**202%**	198%	183%	219%	205%	206%	210%	210%	194%	184%
Plan fiduciary net position as a percentage of the total pension liability	**58.6%**	57.1%	60.7%	50.7%	54.4%	54.1%	53.3%	56.9%	59.9%	59.9%

Schedule of Pension Plan Contributions
Required Supplementary Information
(Millions)

Years Ended December 31,	**2023**	2022	2021	2020	2019	2018	2017	2016	2015	2014
Required Contributions:										
From the Authority	**25.60**	$23.20	$22.10	$22.10	$20.60	$19.80	$17.70	$15.60	$14.80	$13.90
From employees	**12.80**	12.30	12.50	12.90	12.40	12.80	12.60	11.80	11.00	10.20
Contributions in relation to the required contributions:										
From the Authority	**25.60**	$23.20	$22.10	$22.10	$20.60	$19.80	$17.70	$15.60	$14.80	$13.90
From employees	**12.80**	12.30	12.50	12.90	12.40	12.80	12.60	11.80	11.00	10.20
Contribution deficiency (excess)	**0**	0	0	0	0	0	0	0	0	0
Authority's covered payroll	**142.80**	137.20	138.30	143.60	138.20	142.30	142.70	140.10	136.40	131.50
Authority's contributions as a percentage of covered payroll	**18.00%**	17.00%	16.00%	15.40%	14.90%	13.90%	12.40%	11.10%	10.90%	10.50%

Schedule of Changes in Net OPEB Liability and Related Ratios
Required Supplementary Information
(Thousands)

Measurement period ending June 30,	2023	2022	2021	2020	2019	2018[1]
Service Cost	$ 6,052	$ 7,098	$ 6,899	$ 6,821	$ 4,641	$ 5,405
Interest on the total OPEB liability	$ 8,910	8,755	9,573	9,425	10,375	10,073
Difference between expected and actual experience	$ (40,154)	177	7,692	242	(12,859)	(291)
Changes of Assumptions	$ (16,422)	(260)	3,975	(2,717)	44,641	0
Benefit payments	$ (10,125)	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
Net change in total OPEB liability	$ (51,739)	5,757	18,326	4,420	37,861	7,934
Total OPEB liability - beginning	$ 299,066	293,309	274,983	270,563	232,702	224,768
Total OPEB liability - ending (a)	$ 247,327	$ 299,066	$ 293,309	$ 274,983	$ 270,563	$ 232,702
Plan fiduciary net position						
Employer contributions	19,243	$ 20,283	$ 18,573	$ 18,812	$ 27,483	$ 14,455
OPEB plan net investment income	(6,923)	(20,631)	(1,686)	5,717	5,501	(120)
Benefit payments	(10,125)	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
OPEB plan administrative expense	(154)	(171)	(167)	(153)	(126)	(104)
Net change in plan fiduciary net position	2,041	(10,532)	6,907	15,025	23,921	6,978
Plan fiduciary net position - beginning	95,249	105,781	98,874	83,849	59,928	52,950
Plan fiduciary net position - ending (b)	97,290	$ 95,249	$ 105,781	$ 98,874	$ 83,849	$ 59,928
Net OPEB liability - ending (a) - (b)	150,037	$ 203,817	$ 187,528	$ 176,109	$ 186,715	$ 172,774
Plan fiduciary net position as a percentage of total OPEB liability	39.34%	31.85%	36.06%	35.96%	30.99%	25.75%
Covered-employee payroll	$ 159,216,510	$ 146,304,252	$ 148,938,030	$ 149,128,347	$ 149,862,640	156,058,022
Net OPEB liability as a percentage of covered-employee payroll	94.23%	139.31%	125.91%	118.09%	124.59%	110.71%

[1] Information is not available for years prior to 2018.

Schedule of OPEB Contributions
Required Supplementary Information
(Thousands)

For December	Actuarially Determined Contribution	Actual Contribution	Contribution Deficiency (Excess)	Covered Employee Payroll	Actual as a % of Covered Payroll
2023	**$ 18,088**	**$ 23,282**	**$ (5,194)**	**$ 158,618**	**14.68%**
2022	17,867	18,133	(266)	145,554	12.46%
2021	18,224	19,606	(1,382)	149,053	13.15%
2020	18,012	18,898	(886)	155,676	12.14%
2019	15,515	17,262	(1,747)	154,791	11.15%
2018	15,364	14,455	909	156,059	9.26%

Notes to Schedule:
Changes of assumptions: Changes of assumptions and other inputs reflect the effects of changes in the discount rate of each period. The following is the discount rate used in this period:

Fiscal Year Ending	Rate
2023	**4.00%**
2022	3.00%
2021	3.50%
2020	3.50%
2019	4.50%

Schedule of Investment Returns
Required Supplementary Information

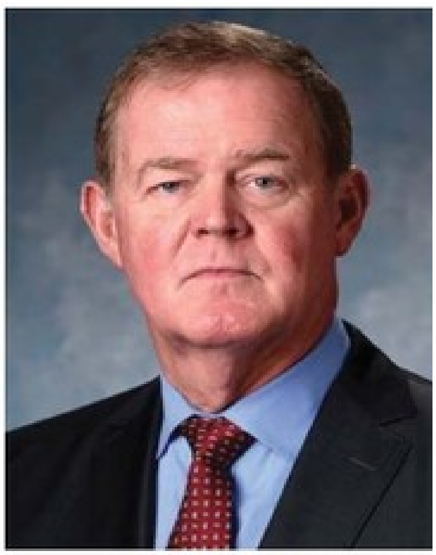
	2023	2022	2021	2020	2019	2018[1]
Annual money-weighted rate of return, net of investment expenses	**2.09%**	(25.89)%	(1.63)%	6.46%	7.96%	(0.21)%

[1] Information is not available for years prior to 2018.

Board of Directors

Peter M. McCoy Jr.
Chairman
Charleston, South Carolina

Chairman McCoy is an attorney and the sole proprietor of McCoy Law Group LLC, a firm located in Charleston, and a former U.S. Attorney for the District of South Carolina.



Stephen H. Mudge
1st Vice Chairman
At-Large
Clemson, South Carolina

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

David F. Singleton
2nd Vice Chairman
Horry County
Myrtle Beach, South Carolina.

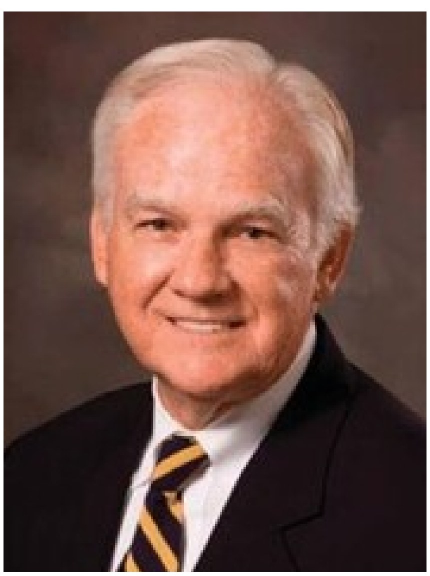
Director Singleton is president of Singleton Properties, a real estate investment and sales firm.

Charles Samuel "Sam" Bennett II
1st Congressional District
Hilton Head Island, South Carolina.

Director Bennett is the President of Sea Pines Community Services Association and former Santee Cooper Vice President of Administration.

Kristofer D. Clark
3rd Congressional District
Easley, South Carolina

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



Charles E. Dalton
4th Congressional District
Greenville, South Carolina

Director Dalton is a retired President and CEO for Blue Ridge Electric Cooperative.

Merrell W Floyd
7th Congressional District
Conway, South Carolina

Director Floyd is a retired staff coordinator for Horry Electric Cooperative.

J. Calhoun Land IV
6th Congressional District
Manning, South Carolina

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

Charles H. "Herb" Leaird
5th Congressional District Sumter,
South Carolina

Director Leaird is the former CEO of Black River Electric Cooperative and also served as CEO of Lynches River Electric Cooperative.

Dan J. Ray
Georgetown County
Georgetown, South Carolina

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

Stacy K. Taylor
2nd Congressional District
Chapin, South Carolina.

Director Taylor is an attorney in Chapin.

John S. West
Berkeley County
Moncks Corner, South Carolina.

Director West is an attorney with West Law Firm in Moncks Corner and a former Santee Cooper General Counsel.

Robert G. Ardis III
Ex Officio, Central Electric Power Cooperative Inc.
Kingstree, South Carolina

Director Ardis is a member of the Central Electric Power Cooperative Inc. Board of Trustees and the President and CEO of Santee Electric Cooperative.

E. Paul Basha
Ex Officio, Central Electric Power Cooperative Inc.
York, South Carolina

Director Basha is the Chairman and a member of the Executive Committee of the Central Electric Cooperative Inc. Board of Trustees and the President and CEO of York Electric Cooperative.

Notes:

Stephen H. Mudge assumed the role of First Vice Chairman, effective Jan. 23, 2023.

Charles Samual "Sam" Bennett II was appointed to represent the 1st Congressional District, a seat previously held by William A. Finn. Director Bennett's term began June 14, 2023.

Stacy K. Taylor was appointed to represent the 2nd Congressional District, which was a vacant seat. Director Taylor's term began June 14, 2023.

John S. West was appointed to represent Berkeley County, a seat previously held by Peggy H. Pinnell. Director West's term began June 14, 2023.

On May 20, 2023, E. Paul Basha assumed the Ex Officio Board Member role previously held by Rob Hochstetler.

Alyssa Leigh Richardson of North Charleston, South Carolina, was appointed to the 6th Congressional District, a seat held in 2023 by J. Calhoun Land IV. Director Richardson's term began Jan. 1, 2024.

Advisory Board

Henry D. McMaster	Governor
Alan Wilson	Attorney General
Mark Hammond	Secretary of State
Brian J. Gaines	Comptroller General
Curtis M. Loftis Jr.	State Treasurer

Notes:

Brian J. Gaines was appointed Comptroller General on May 12, 2023, by South Carolina Governor Henry D. McMaster. The position was previously held by Richard Eckstrom.

Leadership

Jimmy D. Staton	President and Chief Executive Officer
Victoria N. Budreau	Chief Customer Officer
Rahul Dembla	Chief Planning Officer
Michael J. Finissi	Chief Operations Officer
Kenneth W. Lott III	Chief Financial and Administration Officer
Monique L. Washington	Chief Audit and Risk Officer
J. Martine "Marty" Watson	Chief Commercial Officer
Pamela J. Williams	Chief Public Affairs Officer and General Counsel

Other Officers

Traci J. Grant	Director of Corporate Services and Corporate Secretary
Dominick G. Maddalone	Senior Director of Innovation and Chief Information Officer
Daniel T. Manes	Controller
Suzanne H. Ritter	Treasurer and Director of Financial Planning

Notes:

J. Martine "Marty" Watson's position changed from Chief Power Supply Officer to Chief Commercial Officer on April 1, 2023.

Michael J. Finissi was named Chief Operations Officer as of April 1, 2023.

Traci Grant was named Director of Inclusive Strategies on January 16, 2024, and will continue her role as Corporate Secretary.

Office Locations

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