NEW ISSUE – Book-Entry

RATINGS: Moody's: "A3"
S&P: "A-"
Fitch: "A-"

In the opinion of Burr Forman McNair, Bond Counsel, under existing law and assuming compliance with the tax covenants described herein, and the accuracy of certain representations and certifications made by the Authority described herein, interest on the 2026A Bonds and the 2026C Bonds is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"). Burr Forman McNair, Bond Counsel, is also of the opinion that interest on the 2026B Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code. Burr Forman McNair, Bond Counsel, is further of the opinion that the interest on the 2026 Bonds will be exempt from all State, county, municipal and school district and other taxes or assessments imposed within the State of South Carolina, except estate, transfer, and certain franchise taxes. See "TAX MATTERS" herein regarding certain other tax considerations.

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$447,175,000*
SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
Revenue Obligations
consisting of:
$210,925,000* 2026 Tax-Exempt Improvement Series A
$106,000,000* 2026 Taxable Improvement Series B
$130,250,000* 2026 Tax-Exempt Refunding Series C

Dated: Date of Delivery **Due: As shown on the inside cover**

The South Carolina Public Service Authority (the "Authority") is issuing its Revenue Obligations, 2026 Tax-Exempt Improvement Series A (the "2026A Bonds"), and Revenue Obligations, 2026 Taxable Improvement Series B (the "2026B Bonds"), for the purpose of (i) financing a portion of the costs of the capital improvement program of the System (as defined in Appendix B hereto), which includes paying down draws previously made by the Authority under its direct placement facilities and/or repaying notes outstanding under its commercial paper facility, and (ii) paying certain costs of issuance of the 2026 Bonds (defined below). The Authority is issuing its Revenue Obligations, 2026 Tax-Exempt Refunding Series C (the "2026C Bonds") for the purpose of (i) refunding the Refunded Bonds (as defined herein), and (ii) paying certain costs of issuance of the 2026 Bonds. The 2026A Bonds, the 2026B Bonds, and the 2026C Bonds, collectively, are referred to herein as the "2026 Bonds." See "PLAN OF FINANCE AND REFUNDING PLAN." Interest on the 2026 Bonds will accrue from their date of delivery and will be payable semiannually on each June 1 and December 1, commencing on June 1, 2026. The 2026 Bonds will be issued only as fully registered bonds in the name of Cede & Co., as nominee of The Depository Trust Company, Brooklyn, New York ("DTC"), which will act as securities depository for the 2026 Bonds under a book-entry only system as described herein, pursuant to which principal and interest payments on the 2026 Bonds will be made. Individual purchases of beneficial interests may be made in book-entry only form, in the principal amount of $5,000 or any integral multiple thereof for the 2026 Bonds. Beneficial owners of the 2026 Bonds will not receive physical delivery of bond certificates. See APPENDIX C – "PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM" attached hereto.

The 2026 Bonds are being issued pursuant to the Act (as defined herein) and pursuant to the authority of and in full compliance with the resolution adopted by the Authority's Board of Directors on April 26, 1999 (the "Master Resolution"), as amended and supplemented from time to time. The Master Resolution, as so amended and supplemented, is hereinafter referred to as the "Revenue Obligation Resolution." See APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION" attached hereto.

The 2026 Bonds are subject to redemption prior to maturity as set forth herein. See "DESCRIPTION OF THE 2026 BONDS – Redemption Provisions – *2026A Bonds*," "– *2026B Bonds*," and "– *2026C Bonds*."

This cover page contains certain information for quick reference only. It is not, and is not intended to be, a summary of this issue. Investors must read the Official Statement in its entirety prior to purchasing the 2026 Bonds to obtain information essential to making an informed investment decision.

The 2026 Bonds are not indebtedness of the State of South Carolina (the "State"), nor of any political subdivision thereof, and neither the State nor any of its political subdivisions is liable thereon, nor are they payable from any funds other than the Revenues (as defined herein) of the Authority pledged to the payment thereof.

An insurance policy for the 2026 Bonds may be obtained, which, if obtained, would insure the scheduled payment of principal and interest on all or a portion of the 2026 Bonds when due. The decision whether or not to obtain such a policy will be made at or about the time of the pricing. No assurance can be given as to whether such an insurance policy will be obtained. See "DESCRIPTION OF THE 2026 BONDS – Potential Bond Insurance."

The 2026 Bonds are offered when, as and if issued and accepted by the Underwriters, subject to the approval of legality by Burr Forman McNair, Charleston, South Carolina, Bond Counsel. Certain legal matters will be passed upon for the Authority by Nixon Peabody LLP, New York, New York, Disclosure Counsel to the Authority. Certain legal matters will be passed upon for the Authority by Carmen H. Thomas, the Authority's Vice President, Chief Legal Officer, and General Counsel. Certain legal matters will be passed upon for the Underwriters by Orrick, Herrington & Sutcliffe LLP, New York, New York, Counsel to the Underwriters. It is expected that delivery of the 2026 Bonds will be made on or about March 4, 2026.

J.P. Morgan **BofA Securities** **Barclays**

Academy Securities, Inc. **Goldman Sachs & Co. LLC** **TD Financial Products**

Truist Securities **Wells Fargo Securities**

February __, 2026

* Preliminary, subject to change.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, PRICES OR YIELDS, AND CUSIP† NUMBERS

$210,925,000*
Revenue Obligations, 2026 Tax-Exempt Improvement Series A

Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP† Number	Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP† Number

$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP† NO. _____
$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP† NO. _____

$106,000,000*
Revenue Obligations, 2026 Taxable Improvement Series B

Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP† Number	Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP† Number

$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP† NO. _____
$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP† NO. _____

---

* Preliminary, subject to change.

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SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

MATURITIES, PRINCIPAL AMOUNTS, INTEREST RATES, PRICES OR YIELDS AND CUSIP[†] NUMBERS

$130,250,000[*]
Revenue Obligations, 2026 Tax-Exempt Refunding Series C

Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP[‡] Number	Maturity (December 1)	Amount	Interest Rate	Yield	CUSIP[†] Number

$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP[†] NO. _____
$__________ _____% Term Bonds due December 1, 20__, Price or Yield _____%, CUSIP[†] NO. _____

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[*] Preliminary, subject to change.

[†] Copyright 2026, American Bankers Association. The CUSIP (Committee on Uniform Securities Identification Procedures) numbers in this Official Statement have been assigned by an organization not affiliated with the Authority or the Underwriters, and such parties are not responsible for the selection or use of the CUSIP numbers. CUSIP® is a registered trademark of the American Bankers Association. CUSIP Global Services ("CGS") is managed on behalf of the American Bankers Association by FactSet Research Systems Inc. The CUSIP numbers are included solely for the convenience of the Holders of the 2026 Bonds and no representation is made as to the correctness of the CUSIP numbers on the applicable 2026 Bonds or as included herein. The CUSIP number assigned to a specific maturity may be changed after the execution and delivery of the 2026 Bonds as a result of various subsequent actions including, but not limited to, a refunding or defeasance in whole or in part or as a result of the procurement of secondary market portfolio insurance or other similar enhancement by investors that is applicable to all or a portion of certain maturities of the 2026 Bonds. Neither the Authority nor the Underwriters has agreed to, nor is there any duty or obligation to, update this Official Statement to reflect any change or correction in the CUSIP numbers herein.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

One Riverwood Drive
Moncks Corner, South Carolina 29461
(843) 761-8000

No dealer, broker, salesman, or other person has been authorized by the Authority or the Underwriters to give any information or to make any representations with respect to the 2026 Bonds other than the information and representations contained in this Official Statement, and if given or made, such other information or representations may not be relied upon as having been authorized by the Authority. This Official Statement does not constitute an offer to sell, or the solicitation of an offer to buy, nor shall there be any sale of the 2026 Bonds by any person in any jurisdiction in which it is unlawful for such person to make such offer, solicitation, or sale. The information set forth herein has been provided by the Authority and other sources which are believed to be reliable. The information and expressions of opinion herein are subject to change without notice, and neither the delivery of this Official Statement, nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the matters described herein since the date hereof.

THE UNDERWRITERS HAVE PROVIDED THE FOLLOWING SENTENCE FOR INCLUSION IN THIS OFFICIAL STATEMENT. THE UNDERWRITERS HAVE REVIEWED THE INFORMATION IN THIS OFFICIAL STATEMENT IN ACCORDANCE WITH, AND AS PART OF, THEIR RESPECTIVE RESPONSIBILITIES TO INVESTORS UNDER THE FEDERAL SECURITIES LAWS AS APPLIED TO THE FACTS AND CIRCUMSTANCES OF THIS TRANSACTION, BUT THE UNDERWRITERS DO NOT GUARANTEE THE ACCURACY OR COMPLETENESS OF SUCH INFORMATION.

All summaries herein of documents are qualified in their entirety by reference to such documents and agreements, and all summaries herein of the 2026 Bonds are qualified in their entirety by reference to the form thereof included in the aforesaid documents and agreements.

THIS OFFICIAL STATEMENT CONTAINS FORWARD-LOOKING STATEMENTS. IN THIS RESPECT, THE WORDS "MAY," "WILL," "FORECAST," "ESTIMATE," "PROJECT," "ANTICIPATE," "EXPECT," "INTEND," "BELIEVE," AND SIMILAR EXPRESSIONS ARE INTENDED TO IDENTIFY FORWARD-LOOKING STATEMENTS. SUCH STATEMENTS ARE BASED ON THE CURRENT EXPECTATIONS OF THE PARTY MAKING SUCH STATEMENTS AS WELL AS ASSUMPTIONS MADE BASED ON THE INFORMATION CURRENTLY AVAILABLE TO SUCH PARTY. A NUMBER OF IMPORTANT FACTORS AFFECTING THE AUTHORITY'S BUSINESS AND FINANCIAL RESULTS THAT COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY FROM THOSE STATED IN THE FORWARD-LOOKING STATEMENTS ARE DISCLOSED IN THIS OFFICIAL STATEMENT. ACTUAL EVENTS OR RESULTS MAY BE MATERIALLY DIFFERENT FROM THOSE EXPRESSED OR IMPLIED IN THE FORWARD-LOOKING STATEMENTS IN THIS OFFICIAL STATEMENT OR MAY NOT OCCUR. ALL ESTIMATES, PROJECTIONS, FORECASTS, ASSUMPTIONS, AND OTHER FORWARD-LOOKING STATEMENTS ARE EXPRESSLY QUALIFIED IN THEIR ENTIRETY BY THE CAUTIONARY STATEMENTS SET FORTH IN THIS OFFICIAL STATEMENT. THESE FORWARD-LOOKING STATEMENTS SPEAK ONLY AS OF THE DATE THEY WERE PREPARED. THE AUTHORITY SPECIFICALLY DISCLAIMS ANY OBLIGATION TO UPDATE OR REVISE ANY FORWARD-LOOKING STATEMENTS TO REFLECT NEW INFORMATION, OR FUTURE OCCURRENCES, OR UNANTICIPATED EVENTS, OR CIRCUMSTANCES AFTER THE DATE OF THIS OFFICIAL STATEMENT.

The Authority may place a copy of this Official Statement on the Authority's website at https://www.santeecooper.com. However, the information presented on the Authority's website, its social media accounts, or any other website is not part of this Official Statement and should not be relied upon in making investment decisions with respect to the 2026 Bonds. Typographical or other errors may have occurred in converting the original source documents to their digital format, and the Authority assumes no liability or responsibility for errors or omissions contained on any website. Further, the Authority disclaims any duty or obligation to update or maintain the availability of the information contained on any website or any responsibility or liability for any damages caused by viruses or other harmful code contained within the electronic files on any website. The Authority also assumes no liability or responsibility for any errors or omissions or for any updates to dated information contained on any website. References to website addresses presented herein are for informational purposes only and may be in the form of a hyperlink solely for the reader's convenience. Unless specified otherwise, such website and the information or links contained therein are not incorporated into, and are not part of, this Official Statement for purposes of, and as that term is defined in, Rule 15c2-12 of the United States Securities and Exchange Commission (the "SEC").

THE 2026 BONDS WILL NOT BE REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED, OR ANY STATE SECURITIES LAWS IN RELIANCE UPON EXEMPTIONS CONTAINED IN SUCH LAWS. THE 2026 BONDS WILL NOT HAVE BEEN RECOMMENDED BY THE SEC OR ANY OTHER FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY, AND NO SUCH COMMISSIONS AND REGULATORY AUTHORITIES WILL HAVE REVIEWED OR PASSED UPON THE ACCURACY OR ADEQUACY OF THIS OFFICIAL STATEMENT. THE REGISTRATION OR QUALIFICATION OF THE 2026 BONDS IN ACCORDANCE WITH THE APPLICABLE PROVISIONS OF SECURITIES LAWS OF ANY JURISDICTION IN WHICH THE 2026 BONDS MAY HAVE BEEN REGISTERED OR QUALIFIED AND THE EXEMPTION THEREFROM IN OTHER JURISDICTIONS CANNOT BE REGARDED AS A RECOMMENDATION THEREOF BY ANY SUCH JURISDICTION. ANY REPRESENTATION TO THE CONTRARY MAY BE A CRIMINAL OFFENSE.

The order and placement of materials in this Official Statement, including the Appendices, are not to be deemed to be a determination of relevance, materiality, or importance, and this Official Statement, including the Appendices, must be considered in its entirety. The offering of the 2026 Bonds is made only by means of this entire Official Statement.

For purposes of compliance with Rule 15c2-12 of the SEC, this document, as the same may be supplemented or corrected by the Authority from time to time (collectively, the "Official Statement"), may be treated as an Official Statement with respect to the 2026 Bonds described herein that is deemed final as of the date hereof (or of any such supplement or correction) by the Authority.

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Official Statement
relating to

$447,175,000*
South Carolina Public Service Authority
Revenue Obligations

consisting of:

$210,925,000* 2026 Tax-Exempt Improvement Series A
$106,000,000* 2026 Taxable Improvement Series B
$130,250,000* 2026 Tax-Exempt Refunding Series C

INTRODUCTION

General

The purpose of this Official Statement, which includes the cover page and the Appendices attached hereto, is to set forth information concerning the Revenue Obligations, 2026 Tax-Exempt Improvement Series A (the "2026A Bonds"), Revenue Obligations, 2026 Taxable Improvement Series B (the "2026B Bonds"), and Revenue Obligations, 2026 Tax-Exempt Refunding Series C (the "2026C Bonds") of the South Carolina Public Service Authority (the "Authority") offered hereby. The 2026A Bonds, the 2026B Bonds, and the 2026C Bonds are referred to herein as the "2026 Bonds."

This Introduction contains certain information for quick reference only. Prospective investors must read the Official Statement in its entirety prior to purchasing the 2026 Bonds to obtain information essential to making an informed investment decision.

The 2026 Bonds are to be issued pursuant to Act No. 887 of the Acts of the State of South Carolina for 1934 and acts supplemental thereto and amendatory thereof (Code of Laws of South Carolina 1976, as amended - Sections 58-31-10 through 58-31-740) (the "Act"), and pursuant to the authority of and in full compliance with the resolution adopted by the Authority's Board of Directors (the "Board") on April 26, 1999 (the "Master Resolution"), as amended and supplemented from time to time, including as supplemented by the Sixty-Fourth Series and Supplemental Resolution (the "Sixty-Fourth Supplemental Resolution") authorizing the 2026A Bonds, the Sixty-Fifth Series and Supplemental Resolution (the "Sixty-Fifth Supplemental Resolution") authorizing the 2026B Bonds, and the Sixty-Sixth Series and Supplemental Resolution (the "Sixty-Sixth Supplemental Resolution") authorizing the 2026C Bonds. The Master Resolution, as so amended and supplemented, is hereinafter referred to as the "Revenue Obligation Resolution." The 2026 Bonds constitute "Obligations" issued under the Revenue Obligation Resolution. The 2026 Bonds and all Obligations heretofore and hereafter issued pursuant to the Revenue Obligation Resolution (collectively, the "Revenue Obligations") are payable on a parity with each other. See "SECURITY FOR THE 2026 BONDS."

The summary of the Revenue Obligation Resolution herein contained is made subject to all of the provisions of such document, and such summary does not purport to be a complete statement of such provisions. Reference is hereby made to such document for further information in connection therewith. Copies of the Revenue Obligation Resolution may be examined at the main office of the Authority in Moncks Corner, South Carolina and on the Authority's website at www.santeecooper.com/about/investors. The Authority's financial statements for the year ended December 31, 2024, are included as APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS" to this Official Statement.

* Preliminary, subject to change.

Capitalized terms used herein and not defined have the meanings given to such terms in APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION."

The South Carolina Public Service Authority

The Authority is a body corporate and politic created by the Act in 1934. The Authority's primary business operation is the production, transmission, and distribution of electrical energy, both at wholesale and retail, to citizens of the State of South Carolina (the "State"). The Authority is one of the nation's largest municipal wholesale utilities, whose electric system serves directly or indirectly approximately two million South Carolinians in all 46 counties of the State. The Authority began electric power operations in 1942.

Under the Act, the Authority is also authorized to construct, own, and operate facilities to treat, transmit, distribute, and sell water at wholesale within the counties of Berkeley, Calhoun, Dorchester, and Orangeburg, and the Town of Santee, South Carolina. The Authority owns and operates the Lake Moultrie Regional Water System and the Lake Marion Regional Water System, two modern drinking water treatment systems serving over 260,000 people. The Lake Moultrie Regional Water System began commercial operation in October 1994, and the Lake Marion Regional Water System began commercial operation in May 2008. Under current State law and by contract, each of the Regional Water Systems (as defined herein) is required to be self-supporting.

Purpose of the 2026 Bonds

The 2026A Bonds and the 2026B Bonds are being issued for the purpose of (i) financing a portion of the costs of the capital improvement program of the System, which includes paying down draws previously made by the Authority under its direct placement facilities and/or repaying notes outstanding under its commercial paper facility, and (ii) paying certain costs of issuance of the 2026 Bonds. The 2026C Bonds are being issued for the purpose of (i) refunding the Refunded Bonds (as defined herein), and (ii) paying certain costs of issuance of the 2026 Bonds. See "PLAN OF FINANCE AND REFUNDING PLAN" and "ESTIMATED SOURCES AND USES OF FUNDS" herein for additional information.

The issuance of the 2026A Bonds and the 2026B Bonds by the Authority for the purposes described above required the approval of the State's Joint Bond Review Committee (the "JBRC"). The authorization for the Series 2026 Bonds was approved at meetings of the JBRC on January 29, 2025 and December 2, 2025. See "THE AUTHORITY – Joint Bond Review Committee Approval."

The issuance of the 2026C Bonds by the Authority for the purposes described above will result in savings in total debt service of the Authority, and therefore, such issuance does not require approval of the JBRC. See "THE AUTHORITY – Joint Bond Review Committee Approval."

Outstanding Parity and Subordinated Indebtedness

Parity Indebtedness

As of January 2, 2026, the Authority had approximately $7.539 billion in aggregate principal amount of Revenue Obligations outstanding under the Revenue Obligation Resolution. Payment of the principal of and interest on the Authority's Variable Rate Revenue Obligations, 2019 Tax-Exempt Refunding Series A (the "2019A Bonds") is secured by an irrevocable direct-pay letter of credit issued by Bank of America, N.A. ("Bank of America") pursuant to a reimbursement agreement between the Authority and Bank of America (the "2019A Reimbursement Agreement"). The Authority's payment obligations to Bank of America under the 2019A Reimbursement Agreement are secured by a lien upon and pledge of Revenues on parity with the pledge securing the Revenue Obligations.

Subordinated Indebtedness

As of January 2, 2026, the Authority had $292,983,000 in aggregate principal amount of Commercial Paper Notes (as defined herein) outstanding, which Commercial Paper Notes are secured by a lien upon and pledge of Revenues junior to the lien and pledge securing the Authority's Revenue Obligations. Payment of the principal of and interest on the outstanding Commercial Paper Notes is currently supported by direct-pay letters of credit issued by Barclays Bank PLC ("Barclays Bank") pursuant to two reimbursement agreements (the "CP Reimbursement Agreements"). Under the CP Reimbursement Agreements, the Authority may issue up to $400,000,000 aggregate principal amount of Commercial Paper Notes the proceeds of which may be used for any lawful corporate purposes, including to pay the principal of and interest on maturing Commercial Paper Notes. The Authority's payment obligations to Barclays Bank under the CP Reimbursement Agreements are secured by a lien upon and pledge of Revenues junior to the lien and pledge securing the Authority's Revenue Obligations and on parity with the lien and pledge securing the Commercial Paper Notes.

The Authority maintains five revolving credit facilities to fund, among other things, working capital expenses and capital expenditures. The loans made under the Revolving Credit Agreements (as defined herein) are secured by a lien on and pledge of Revenues that is junior to the lien and pledge securing the Authority's Revenue Obligations and is on parity with the Commercial Paper Notes. The Revolving Credit Agreements provide the Authority with borrowing capacity in an aggregate amount of $1,100,000,000. As of January 2, 2026, there were $514,765,000 of loans drawn and outstanding under the Revolving Credit Agreements.

See "THE AUTHORITY – Outstanding Indebtedness" herein for a more detailed description of the Authority's outstanding debt, including the CP Reimbursement Agreements and the Revolving Credit Agreements.

Additional Indebtedness

Additional series of Revenue Obligations may be issued on a parity with the 2026 Bonds under the Revenue Obligation Resolution without limitation and without compliance with any additional bonds test, provided there is no default under the Revenue Obligation Resolution. The Revenue Obligation Resolution does not prohibit the issuance of obligations secured by a pledge of the Revenues junior and subordinate to the pledge securing the Revenue Obligations. In addition, the Authority may issue obligations secured by a pledge of revenues derived from separate utility systems not included in the System. See "SECURITY FOR THE 2026 BONDS" and APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION – Separate Systems."

The Authority is required by law to obtain the approval of the JBRC prior to the issuance of certain bonds, notes, or other indebtedness, including any refinancing that does not achieve a savings in total debt service. See "THE AUTHORITY – Joint Bond Review Committee Approval."

Nuclear Memorandum of Understanding

In January 2025, the Authority launched a process for requesting proposals from parties interested in acquiring one or both of the two partially built AP1000 nuclear generating units (formerly referred to as Virgil C. Summer Nuclear Station Units 2 and 3) located at the Virgil C. Summer Nuclear Generating Station in Fairfield County, South Carolina (the "Nuclear Units") and the related assets, completing one or both of such units, or pursuing alternative uses of the equipment and/or the site, with bids due in May 2025. The Authority previously approved the wind-down and suspension of construction of these units and the preservation and protection of the site and related components and equipment in July 2017. The Authority received 14 formal proposals in response to its request for proposals. After a comprehensive review process, the Authority in October 2025 approved the proposal from Brookfield Asset Management ("Brookfield") to complete the Nuclear Units.

In December 2025, the Authority and Brookfield executed a Memorandum of Understanding ("MOU") relating to Brookfield's proposal to acquire and potentially complete construction of the Nuclear Units. The MOU sets forth the principal binding and non-binding terms and conditions for Brookfield to acquire and develop the

Nuclear Units (the "Transaction"). A copy of the MOU is available at the following address: https://www.scnuclear.com/project-overview. *The information available at the preceding website is not incorporated by reference herein*.

The binding provisions of the MOU, among other things, establish an exclusive feasibility period, a timeline for reaching a final investment decision regarding the Transaction, and the reimbursement of certain expenses incurred by the Authority in connection with the Transaction, including expenses incurred prior to the execution of the MOU and through its termination, in each case subject to the terms and limitations set forth in the MOU. The proposed non-binding Transaction terms include a $2.7 billion cash payment to the Authority if Brookfield reaches a final investment decision to move forward with the Transaction, subject to the terms of the MOU and the negotiation and execution of definitive agreements, plus a targeted 25% ownership share for the Authority as tenants in common, with proportional capacity, once the Nuclear Units begin commercial operation. The Authority's ownership share (as tenants in common) could be decreased, subject to a floor, or the Authority could receive an additional cash payment at the time of commercial operation, in each case as provided in the MOU, depending on the final cost of completing the Nuclear Units. Among other termination rights, the Authority has the option to terminate the MOU if Brookfield proposes changes to either of these non-binding terms (the $2.7 billion cash payment or the targeted 25% ownership share). If the $2.7 billion cash payment is received by the Authority pursuant to the MOU, the Authority currently expects to apply such amount to pay or defease portions of the Authority's outstanding tax-exempt bonds that are allocable to expenditures for the Nuclear Units. The Authority is unable to predict the outcome of the feasibility period, including whether the Transaction will be ultimately consummated. There can be no assurance that Brookfield will reach a final investment decision, that definitive agreements will be executed, or that the Transaction will be consummated on the terms described or at all. See "NUCLEAR UNITS."

Capital Plan

The Authority currently estimates the total cost of its capital improvement program for 2026 through 2028 at approximately $3.5 billion, comprised of approximately $1.4 billion for new generating resources, $1.1 billion for transmission projects to support system growth and reliability, $800 million for general improvements to the System, $110 million for environmental compliance expenditures for the electric system, $10 million related to Federal Energy Regulatory Commission ("FERC") relicensing, and $85 million for the Regional Water Systems capital improvement program, which includes $45 million for compliance with regulation of per- and polyfluoroalkyl substances ("PFAS"). The Authority regularly evaluates prospective energy demand from existing and potential new customers and annually updates its load growth forecasts for integrated resource planning. In 2025, the Authority made an upward adjustment of 865 MW to the 2037 winter peak forecast, indicating a compound annual growth rate of 1.7 percent. The Authority currently estimates that data centers represent approximately 70 percent of its projected total load growth over the next 10 years. See "THE AUTHORITY – Capital Improvement Program and Future Financings," "CUSTOMER BASE – Direct Customers – Large Industrial and Military – *Planning for Load Growth from Data Centers*," and "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES – Integrated Resource Planning – *2025 Annual Update to the Integrated Resource Plan*."

Cook Settlement, End of Rate Freeze Period and Recovery of Cook Rate Freeze Exceptions

A class action lawsuit filed in August 2017 relating to the Authority's decision to suspend construction of the Nuclear Units was resolved in March 2020 with the parties entering into a settlement agreement (the "Cook Settlement Agreement") that included, among other things, the Authority's agreement to hold its rates consistent with rates projected in the 2019 Reform Plan (as defined herein) for a period beginning in August 2020 and ending in January 2025 (the "Rate Freeze Period"), subject to certain permitted exceptions for costs and expenses incurred during such period ("Cook Rate Freeze Exceptions") which exceptions could be collected by the Authority after the Rate Freeze Period ended (such agreement to hold rates is referred to herein as the "Rate Freeze"). As required by the Cook Settlement Agreement, the Authority identified and included the Cook Rate Freeze Exceptions in reports filed annually with South Carolina Court of Common Pleas, Greenville County (the "Court"). The total amount of

Cook Rate Freeze Exceptions reported by the Authority in the Annual Cook Compliance Reports (as defined herein) filed through April 30, 2025 was $951.4 million.

As described under "FINANCIAL INFORMATION – Cook Exceptions Regulatory Asset and Cook Deferred Expenses," the Board approved the use of regulatory accounting to establish a regulatory asset (the "Cook Exceptions Regulatory Asset") and defer the recognition of the expenses that qualify for such regulatory accounting treatment, including any future adjustments to the amount of such expenses (the "Cook Deferred Expenses"). While the use of regulatory accounting deferred the recognition of these expenses during the Rate Freeze Period, it did not defer the Authority's obligation to pay these expenses. The Authority has been funding a portion of these expenses on an interim basis from the proceeds of the issuance of its Commercial Paper Notes and draws on the Revolving Credit Agreements.

In June 2025, the Court approved an agreement allowing the Authority to recover $550 million of the Cook Rate Freeze Exceptions (the "Resolution Amount"), plus interim interest incurred on debt incurred to finance the Resolution Amount from January 1, 2025 through June 30, 2025, plus the costs of issuance of the debt incurred to finance the Resolution Amount and the interim interest (together, the "Recovery Amount"). Under the terms of the Exceptions Agreement (as defined herein), the Authority may finance the Recovery Amount from amounts borrowed under the Authority's Revolving Credit Agreements and/or the issuance of Commercial Paper Notes. As of January 2, 2026, the Authority has borrowed under its Revolving Credit Agreements or issued Commercial Paper Notes in a combined total amount of approximately $562.5 million to fund a portion of the Cook Deferred Expenses, of which amount approximately $547.3 million is outstanding.

The Recovery Amount will be financed by the Authority and collected via a line-item charge (the "Cook Charge") on customer bills over the 10-year period from July 1, 2025 to June 30, 2035. The Cook Charge will consist of the amount of debt service on the debt issued to finance the Recovery Amount and amounts to collect an 8% contribution to the Capital Improvement Fund, payments to the State, and sums in lieu of taxes, in each case related to that debt service. The Authority began collecting the Cook Charge from its retail customers through its deferred cost recovery rider and from Central Electric Power Cooperative, Inc. ("Central") on its invoices in July 2025.

In accordance with the terms of the Cook Settlement Agreement, as of January 15, 2025, the Rate Freeze ended and no longer applies to any Authority customer, allowing the Authority to increase its rates, and to restart adjust-to-actual cost rates for Central, and certain automatic adjustments for other customers, including fuel and demand sales adjustments. Approximately 75% of the Authority's costs are recovered from these automatic rate adjustments. In December 2024, the Board of the Authority approved a system average 4.9% base rate increase which took effect in April of 2025.

The Resolution Amount of $550 million in the Exceptions Agreement will result in the Authority collecting 78% of the $703.8 million Cook Exceptions Regulatory Asset recorded as of December 31, 2024. The Authority wrote down the Cook Exceptions Regulatory Asset to $550 million in the fiscal year ending December 31, 2024, which increased expenses by $154 million and reduced reinvested earnings by this same amount for such fiscal year.

For additional information, see "RATES AND RATE COMPARISON – End of Rate Freeze Period and 2025 Rate Adjustments."

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PLAN OF FINANCE AND REFUNDING PLAN

2026A Bonds and 2026B Bonds. A portion of the proceeds of the 2026A Bonds and the 2026B Bonds, together with other available moneys of the Authority, will be used to (i) finance a portion of the costs of the capital improvement program of the System which includes paying down draws previously made by the Authority under its direct placement facilities and/or repaying notes outstanding under its commercial paper facility, and (ii) pay certain costs of issuance of the 2026 Bonds. See "THE AUTHORITY – Capital Improvement Program and Future Financings."

2026C Bonds. A portion of the proceeds of the 2026C Bonds, together with other available moneys of the Authority, will be applied to refund (i) all or a portion of the Revenue Obligations, 2014 Tax-Exempt Refunding Series C set forth in the following table on April 3, 2026*, all or a portion of the Revenue Obligations, 2015 Tax-Exempt Refunding and Improvement Series A set forth in the following table on April 3, 2026*, and all or a portion of the Revenue Obligations, 2016 Tax-Exempt Refunding Series A set forth in the following table on June 1, 2026* (collectively, the "Refunded Bonds"), and to (ii) pay certain costs of issuance of the 2026 Bonds. The refinancing of the Refunded Bonds will result in debt service savings. The refinancing of the Refunded Bonds is contingent upon the delivery of the 2026C Bonds. The Refunded Bonds will not include any tax-exempt bonds of the Authority which were issued to finance costs allocable to the Nuclear Units.

Refunded Bonds*

Series	Maturity Date (December 1)	Outstanding Principal Amount	Principal Amount to be Refunded	Interest Rate	CUSIP† (837151)
2014C	2033	$10,000,000	$9,750,000	3.500%	KP3
2014C	2036	10,000,000	9,750,000	4.000	KR9
2015A	2032	1,775,000	1,775,000	3.500	MJ5
2015A	2033	1,925,000	1,925,000	3.500	MK2
2015A	2034	1,990,000	1,990,000	3.500	ML0
2016A	2026	9,860,000	3,200,000	5.000	PH6
2016A	2027	13,820,000	4,485,000	5.000	PJ2
2016A	2028	12,515,000	4,060,000	5.000	QD4
2016A	2029	33,410,000	10,850,000	5.000	PK9
2016A	2030	35,400,000	11,495,000	5.000	PL7
2016A	2031	33,620,000	10,915,000	5.000	PM5
2016A	2032	24,845,000	8,065,000	5.000	PZ6
2016A	2033	47,030,000	15,270,000	5.000	PP8
2016A	2034	49,380,000	16,035,000	5.000	PQ6
2016A	2035	30,135,000	9,785,000	5.000	QA0
2016A	2036	54,265,000	17,620,000	5.000	PS2
2016A	2037	56,985,000	18,505,000	5.000	PT0
2016A	2038	23,765,000	7,715,000	5.000	PU7

Moneys sufficient to pay the principal of and interest on the Refunded Bonds on the payment dates therefor will be derived from a portion of the proceeds of the 2026C Bonds and other available funds of the Authority (the "Refunding Proceeds"). Simultaneously with the issuance of the 2026C Bonds, the Authority will enter into an escrow deposit agreement for the Refunded Bonds (the "Escrow Deposit Agreement") with The Bank of New York Mellon Trust Company, N.A., as escrow agent (the "Escrow Agent"). The Authority will deposit the Refunding Proceeds allocable to the Refunded Bonds with the Escrow Agent pursuant to the Escrow Deposit Agreement. The Escrow Deposit Agreement will provide for such Refunding Proceeds to be applied to the purchase of Permitted Investments that will mature and bear interest at times and in amounts sufficient, together with other

* Preliminary, subject to change.
† CUSIP numbers are provided for convenience of reference only. None of the Underwriters or the Authority, or their agents or counsel, assumes responsibility for the accuracy or completeness of such numbers.

moneys on deposit, to pay the principal of, redemption premium, if any, and interest on the Refunded Bonds on the redemption dates set forth in the Escrow Deposit Agreement.

The accuracy of the mathematical computations of the adequacy of the principal of and interest on the securities and the moneys to be on deposit with the Escrow Agent to provide for the payment on the redemption date of the principal of, redemption premium, if any, and interest on the Refunded Bonds will be verified at the time of delivery of the 2026C Bonds by Integrity Public Finance Consulting LLC. See “VERIFICATION OF MATHEMATICAL COMPUTATIONS” herein.

Upon deposit of the Refunding Proceeds with the Escrow Agent pursuant to the Escrow Deposit Agreement and in compliance with certain other provisions of the Revenue Obligation Resolution, the Refunded Bonds shall no longer be deemed “Outstanding” within the meaning of the Revenue Obligation Resolution.

ESTIMATED SOURCES AND USES OF FUNDS

The table below sets forth the estimated sources and uses of funds in connection with the issuance of the 2026 Bonds.

Sources of Funds	
Principal Amount of the 2026 Bonds	$
[Net] Original Issue Premium	
Other Available Funds of the Authority	
Total	$
Application of Funds	
Deposit to the Bond Proceeds Fund[1]	$
Deposit to the Escrow Account to refund Refunded Bonds	
Financing Costs[2]	
Total	$

(1) Includes $__________ to be applied to paying down draws previously made by the Authority under its direct placement facilities and/or repaying notes outstanding under its commercial paper facility.
(2) Includes 2026 Bonds costs of issuance, underwriters’ discount, bond insurance premium, and additional proceeds.

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DEBT SERVICE REQUIREMENTS

The following table sets forth on an accrual basis the estimated annual debt service due on the Authority's outstanding Revenue Obligations, principal of and interest on the 2026 Bonds and total debt service on all Revenue Obligations to be outstanding after the issuance of the 2026 Bonds in each calendar year indicated. **Amounts are shown in thousands of dollars and are rounded up or down to the nearest one thousand dollars**.

Year Ending Dec. 31[1]	Total Debt Service on Outstanding Revenue Obligations[2][3][4]	Principal on 2026 Bonds	Interest on 2026 Bonds	Total Debt Service on the 2026 Bonds and Outstanding Revenue Obligations
2026	$516,847	$	$	$
2027	524,813			
2028	538,946			
2029	523,813			
2030	527,004			
2031	524,633			
2032	524,742			
2033	527,436			
2034	526,378			
2035	516,503			
2036	527,123			
2037	499,488			
2038	474,481			
2039	457,101			
2040	458,198			
2041	457,654			
2042	455,797			
2043	435,805			
2044	465,107			
2045	470,770			
2046	445,134			
2047	387,569			
2048	385,723			
2049	379,087			
2050	355,737			
2051	357,972			
2052	352,365			
2053	318,727			
2054	258,991			
2055	147,814			
2056	39,767			
Total	$13,381,525	$	$	$

(1) Debt service payments due January 1 of the next succeeding year are included in the prior year's debt service payments.

(2) Excludes debt service on outstanding Commercial Paper Notes and loans under the Revolving Credit Agreements, which are secured on a subordinate basis to the Revenue Obligations.

(3) Net of Subsidy Payments (hereinafter defined). At time of issuance of the Authority's Revenue Obligations, 2010 Series C Bonds (the "2010C Bonds"), subject to the Authority's compliance with certain requirements under the American Recovery and Reinvestment Act of 2009 and Code, the Authority expected to receive cash subsidy payments from the United States Treasury which were expected to equal 35% of the interest payable on the 2010C Bonds (any such payment, a "Subsidy Payment"). Pursuant to the requirements of the Federal Balanced Budget and Emergency Deficit Control Act of 1985, as amended, certain automatic reductions took place effective March 1, 2013, including a reduction in refundable credits under Section 6431 of the Code applicable to certain qualified bonds, including the Subsidy Payment with respect to the 2010C Bonds. As a result, a projected sequestration reduction rate has been applied to all Subsidy Payments. The debt service on the Revenue Obligations has been adjusted to reflect such reductions.

(4) Excludes debt service on the Refunded Bonds. See "PLAN OF FINANCE AND REFUNDING PLAN." Interest on the 2019A Bonds is projected at an interest rate of 2.90% for 2026 and 2.75% thereafter until maturity. Actual outstanding principal amounts and interest rates are updated through January 1, 2026.

DESCRIPTION OF THE 2026 BONDS

General

The 2026 Bonds will be issued in the aggregate principal amounts, mature on the dates, and bear interest from their date of delivery at the respective rates per annum set forth on pages (i) and (ii) hereof.

Interest on the 2026 Bonds will be payable semiannually on June 1 and December 1 of each year commencing on June 1, 2026 (each, an “Interest Payment Date”). The 2026 Bonds are issuable only in fully registered form in denominations of $5,000 or any integral multiple thereof. The record date for the payment of principal of and interest on the 2026 Bonds will be the May 15 or November 15 immediately preceding an Interest Payment Date (the “Record Date”). The 2026 Bonds are being issued in book-entry only form and are registered in the name of Cede & Co., as nominee for The Depository Trust Company (“DTC”). See APPENDIX C – “PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM” attached hereto.

Redemption Provisions – 2026A Bonds*

Optional Redemption of 2026A Bonds

The 2026A Bonds maturing on and after December 1, 2036, are subject to redemption prior to maturity at the election of the Authority on any Business Day on or after June 1, 2036, in whole or in part, at a Redemption Price of 100% of the principal amount thereof together with accrued interest, if any, to the redemption date.

Mandatory Redemption of 2026A Bonds

The $__________ principal amount 2026A Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Fourth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	Principal Amount

† Final Maturity Date.

The $__________ principal amount 2026A Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Fourth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	Principal Amount

† Final Maturity Date.

* Preliminary, subject to change.

At its option, to be exercised on or before the forty-fifth (45th) day next preceding any mandatory redemption date, the Authority may (i) deliver to the Paying Agent for cancellation 2026A Bonds subject to mandatory redemption in part on such redemption date, in any aggregate principal amount desired, or (ii) receive a credit in respect of its mandatory redemption obligation for any 2026A Bonds of a maturity subject to mandatory redemption in part on such redemption date, which, prior to such date, have been purchased or redeemed (otherwise than through the operation of the mandatory redemption requirement) by the Authority and cancelled by the Paying Agent and not theretofore applied as a credit against any mandatory redemption obligation. Each such 2026A Bond so delivered or previously purchased or redeemed shall be credited by the Paying Agent at 100% of the principal amount thereof on the obligation of the Authority on such respective mandatory redemption obligations in chronological order (except as may be otherwise authorized by the Authority in writing), and the principal amount of such 2026A Bonds to be redeemed by operation of the mandatory redemption requirement shall be accordingly reduced.

Selection of 2026A Bonds to be Redeemed

Whenever less than all of the outstanding 2026A Bonds of a maturity are to be redeemed on any one date, the Trustee will select the 2026A Bonds to be redeemed from the outstanding 2026A Bonds of such maturity by lot (provided that so long as the 2026A Bonds shall remain immobilized at DTC, such 2026A Bonds shall be selected in such manner as DTC shall determine); provided, however, that for any 2026A Bond of a denomination of more than the minimum denomination, the portion of such 2026A Bond to be redeemed must be in a principal amount equal to such minimum denomination or an integral multiple thereof.

Redemption Provisions – 2026B Bonds*

Optional Redemption of 2026B Bonds

The 2026B Bonds are subject to redemption prior to their respective maturities at the option of the Authority, in whole or in part, on any Business Day, at the Make-Whole Redemption Price (as defined below) determined by the Authority. If the 2026B Bonds are redeemable in part, such redemptions shall occur by lot within a maturity in accordance with the procedures established by DTC as then in effect. Notwithstanding the foregoing, if at any time the Make-Whole Redemption Price is a price greater than the price the Authority can legally agree to pay to optionally redeem the 2026B Bonds under the provisions of the Act (currently 105%), the Authority shall not have an option to redeem the 2026B Bonds at that time.

"*Make-Whole Redemption Price*" means the greater of (i) the issue price of the 2026B Bonds (but not less than 100% of the principal amount) to be redeemed, as applicable, or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the 2026B Bonds to be redeemed to the applicable maturity date, not including any portion of those payments of interest accrued and unpaid as of the date on which the 2026B Bonds are to be redeemed, discounted to the date on which such 2026B Bonds are to be redeemed on a semi-annual basis, assuming a 360-day year consisting of twelve 30-day months, at the "Treasury Rate" (described below) plus ___ basis points, and unpaid interest on such 2026B Bonds to be redeemed to but not including the respective redemption date.

"*Business Day*" means (i) a day other than a day on which commercial banks located in New York, New York or the city or cities in which the designated office of the Trustee or the Paying Agent are required or authorized by law to close, and (ii) a day other than a day on which the New York Stock Exchange is closed.

"*Treasury Rate*" means, with respect to any redemption date for any applicable maturity of a 2026B Bond, the yield to maturity of U.S. Treasury securities with a constant maturity most nearly equal to the period from the redemption date to the maturity date of such 2026B Bond to be redeemed (taking into account any sinking fund installments for such 2026B Bonds); provided, however, that if the period from

* Preliminary, subject to change.

the applicable redemption date to such maturity date (taking into account any sinking fund installments for such 2026B Bonds) is less than one year, the yield to maturity of the U.S. Treasury securities with a constant maturity of one year shall be used, in each case as compiled and published in the most recent Federal Reserve Release H.15 which has become publicly available at least two Business Days, but not more than 45 calendar days, prior to the redemption date (excluding inflation or indexed securities) or, if such Release is no longer published, any publicly available source of similar market data reasonably selected by the Trustee.

Mandatory Redemption of 2026B Bonds

The $__________ principal amount 2026B Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Fifth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	**Principal Amount**

† Final Maturity Date.

The $__________ principal amount 2026B Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Fifth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	**Principal Amount**

† Final Maturity Date.

At its option, to be exercised on or before the forty-fifth (45th) day next preceding any mandatory redemption date, the Authority may (i) deliver to the Paying Agent for cancellation 2026B Bonds subject to mandatory redemption in part on such redemption date, in any aggregate principal amount desired, or (ii) receive a credit in respect of its mandatory redemption obligation for any 2026B Bonds of a maturity subject to mandatory redemption in part on such redemption date, which, prior to such date, have been purchased or redeemed (otherwise than through the operation of the mandatory redemption requirement) by the Authority and cancelled by the Paying Agent and not theretofore applied as a credit against any mandatory redemption obligation. Each such 2026B Bond so delivered or previously purchased or redeemed shall be credited by the Paying Agent at 100% of the principal amount thereof on the obligation of the Authority on such respective mandatory redemption obligations by lot (except as may be otherwise authorized by the Authority in writing), and the principal amount of such 2026B Bonds to be redeemed by operation of the mandatory redemption requirement shall be accordingly reduced.

Selection of 2026B Bonds to be Redeemed

If the 2026B Bonds are registered in book-entry only form and so long as DTC or a successor securities depository is the sole registered owner of the 2026B Bonds, if less than all of the 2026B Bonds of a maturity are to be redeemed, the particular 2026B Bonds or portions thereof to be redeemed will be selected by lot by DTC for redemption in accordance with the DTC procedures then in effect. Any failure of DTC to make such determination will not affect the sufficiency or the validity of the redemption of 2026B Bonds to be redeemed. If the 2026B Bonds are not registered in book-entry form and in the event that less than all of the 2026B Bonds of any applicable maturity are to be redeemed, the particular 2026B Bonds or portions thereof to be redeemed will be selected by the Trustee pro rata in such manner as the Trustee shall deem appropriate and fair; provided, however, that for any 2026B Bond of a denomination of more than the minimum denomination, the portion of such 2026B Bond to be redeemed must be in a principal amount equal to such minimum denomination or an integral multiple thereof.

Redemption Provisions – 2026C Bonds*

Optional Redemption of 2026C Bonds

The 2026C Bonds maturing on and after December 1, 2036, are subject to redemption prior to maturity at the election of the Authority on any Business Day on or after June 1, 2036, in whole or in part, at a Redemption Price of 100% of the principal amount thereof together with accrued interest, if any, to the redemption date.

Mandatory Redemption of 2026C Bonds

The $__________ principal amount 2026C Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Sixth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	Principal Amount

† Final Maturity Date.

The $__________ principal amount 2026C Bonds maturing on December 1, 20__, are subject to mandatory redemption from sinking fund installments required by the Sixty-Sixth Supplemental Resolution, without premium, plus accrued interest to the redemption date, on December 1 of each of the following years and in the amounts as follows:

Year (December 1)	Principal Amount

† Final Maturity Date.

At its option, to be exercised on or before the forty-fifth (45^{th}) day next preceding any mandatory redemption date, the Authority may (i) deliver to the Paying Agent for cancellation 2026C Bonds subject to mandatory redemption in part on such redemption date, in any aggregate principal amount desired, or (ii) receive a credit in respect of its mandatory redemption obligation for any 2026C Bonds of a maturity subject to mandatory redemption in part on such redemption date, which, prior to such date, have been purchased or redeemed (otherwise than through the operation of the mandatory redemption requirement) by the Authority and cancelled by the Paying Agent and not theretofore applied as a credit against any mandatory redemption obligation. Each such 2026C Bond

* Preliminary, subject to change.

so delivered or previously purchased or redeemed shall be credited by the Paying Agent at 100% of the principal amount thereof on the obligation of the Authority on such respective mandatory redemption obligations in chronological order (except as may be otherwise authorized by the Authority in writing), and the principal amount of such 2026C Bonds to be redeemed by operation of the mandatory redemption requirement shall be accordingly reduced.

Selection of 2026C Bonds to be Redeemed

Whenever less than all of the outstanding 2026C Bonds of a maturity are to be redeemed on any one date, the Trustee will select the 2026C Bonds to be redeemed from the outstanding 2026C Bonds of such maturity by lot (provided that so long as the 2026C Bonds shall remain immobilized at DTC, such 2026C Bonds shall be selected in such manner as DTC shall determine); provided, however, that for any 2026C Bond of a denomination of more than the minimum denomination, the portion of such 2026C Bond to be redeemed must be in a principal amount equal to such minimum denomination or an integral multiple thereof.

Notice of Redemption

Notice of redemption will be given by first-class mail by the Trustee to the owners of any 2026 Bonds designated for redemption in whole or in part not less than twenty (20) days before the redemption date. Each notice of redemption will state the redemption date, the redemption place, and the redemption price (or method of determining the Redemption Price in the case of redemption at the Make-Whole Redemption Price), and will designate the principal amount (or portion thereof in the case of partial redemption) which is to be redeemed and state that the interest thereon or portions thereof designated for redemption will cease to accrue from and after such redemption date and that on such redemption date there will become due and payable on each of the 2026 Bonds or portions thereof designated for redemption the redemption price thereof. The failure to mail such notice with respect to any 2026 Bonds will not affect the validity of the proceedings for the redemption of any other 2026 Bonds with respect to which notice was so mailed.

Any notice of optional redemption of 2026 Bonds may state that it is conditioned upon receipt by the Trustee of moneys sufficient to pay the redemption price of such 2026 Bonds, or upon the satisfaction of any other condition, or that it may be rescinded upon the occurrence of any other event, and any conditional notice so given may be rescinded at any time before payment of such redemption price if any such condition so specified is not satisfied or if any such other event occurs. Notice of such rescission shall be given by the Trustee to affected owners of 2026 Bonds as promptly as practical upon the failure of such condition or the occurrence of such event.

Registration and Transfer; Payment

The 2026 Bonds may be transferred only on the books of the Authority held at the designated corporate trust office of the Trustee, as Registrar. Interest on any 2026 Bonds will be paid to the person in whose name such 2026 Bond is registered on the applicable Record Date. At such time, if any, as the 2026 Bonds are no longer subject to the book-entry only system of registration and transfer described in APPENDIX C – "PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM" attached hereto, interest on the 2026 Bonds will be payable by check or draft of the Trustee, as Paying Agent, mailed to the registered owners by first-class mail (or, to the extent permitted by the Revenue Obligation Resolution, by wire transfer). At such time, if any, as the 2026 Bonds are no longer subject to such book-entry only system of registration and transfer, the principal of all 2026 Bonds will be payable on the date of maturity or redemption thereof upon presentation and surrender at the designated corporate trust office of the Paying Agent.

For so long as a book-entry system is used for determining beneficial ownership of the 2026 Bonds, such principal and interest will be payable to DTC or its nominee. Disbursement of such payments to the Direct Participants is the responsibility of DTC and disbursement of such payments to the Beneficial Owners of the 2026 Bonds is the responsibility of the Direct Participants or the Indirect Participants. See APPENDIX C – "PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM" attached hereto.

Book-Entry-Only System

DTC will act as securities depository for the 2026 Bonds. The 2026 Bonds will be issued as fully-registered bonds registered in the name of Cede & Co. (DTC's nominee name) or such other name as may be requested by an authorized representative of DTC. One fully-registered certificate will be issued for each Series and maturity of the 2026 Bonds, each in the aggregate principal amount of such Series and maturity, and will be deposited with DTC. Beneficial interests in the 2026 Bonds may be held through DTC, directly as a participant or indirectly through organizations that are participants in such System. See APPENDIX C – "PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM" for a description of DTC, certain of its responsibilities, and the provisions for registration and registration of transfer of the 2026 Bonds if the book-entry-only system of registration is discontinued.

Potential Bond Insurance

A municipal bond insurance policy (the "Policy") may be obtained from a bond insurer (the "Bond Insurer") for all or a portion of the 2026 Bonds (any such portion of the 2026 Bonds, if so insured, the "Insured 2026 Bonds") which, if obtained, would insure the scheduled payment of principal of and interest on the Insured 2026 Bonds when due. The decision whether or not to obtain such a Policy will be made at or about the time of the pricing of the 2026 Bonds and will be based upon, among other things, market conditions at the time of such pricing. No assurance can be given as to whether such Policy will be obtained.

If a Policy is obtained and in the event of default of the payment of principal or interest with respect to the Insured 2026 Bonds when all or some becomes due, any owner of the Insured 2026 Bonds shall have a claim under the Policy issued by the Bond Insurer for such payments. However, in the event of any acceleration of the due date of such principal by reason of redemption, other than any advancement of maturity pursuant to a mandatory sinking fund payment, the payments are to be made in such amounts and at such times as such payments would have been due had there not been any such acceleration. If a Policy is obtained, the Policy does not insure against redemption premium, if any. If a Policy is obtained, the payment of principal and interest in connection with mandatory or optional prepayment of the Insured 2026 Bonds by the Authority which is recovered by the Authority from any Owner as a voidable preference under applicable bankruptcy law is covered by the Policy; however, such payments will be made by the Bond Insurer at such time and in such amounts as would have been due absent such prepayment by the Authority unless the Bond Insurer chooses to pay such amounts at an earlier date.

Under most circumstances, default of payment of principal and interest does not obligate acceleration of the obligations of the Bond Insurer without appropriate consent. If a Policy is obtained, the Bond Insurer may direct and must consent to any remedies, and the Bond Insurer's consent may be required in connection with amendments to any applicable bond documents.

If a Policy is obtained and in the event the Bond Insurer is unable to make payment of principal and interest as such payments become due under the Policy, the Insured 2026 Bonds are payable solely from the moneys received pursuant to the applicable bond documents. In the event the Bond Insurer becomes obligated to make payments with respect to the Insured 2026 Bonds, no assurance is given that such event will not adversely affect the market price of the Insured 2026 Bonds or the marketability (liquidity) for the Insured 2026 Bonds.

The long-term ratings on the Insured 2026 Bonds are dependent in part on the financial strength of the Bond Insurer and its claim paying ability. The Bond Insurer's financial strength and claims paying ability are predicated upon a number of factors which could change over time. If a Policy is obtained, no assurance is given that the long-term ratings of the Bond Insurer and of the ratings on the Insured 2026 Bonds so insured by the Bond Insurer will not be subject to downgrade and such event could adversely affect the market price of the Insured 2026 Bonds or the marketability (liquidity) for the Insured 2026 Bonds. For a description of the rating on the 2026 Bonds, see "RATINGS" herein.

If a Policy is obtained, none of the Authority, Bond Counsel, the Municipal Advisor (as defined herein), the Underwriters (as defined herein), or any of their counsel will make an independent investigation of the claims paying ability of the Bond Insurer, and no assurance or representation regarding the financial strength or projected financial strength of the Bond Insurer will be given. Therefore, when making an investment decision with respect to the Insured 2026 Bonds, potential investors should carefully consider the ability of the Authority to pay principal and interest on the Insured 2026 Bonds assuming that the Policy is not available, and the claims paying ability of the Bond Insurer through final maturity of the Insured 2026 Bonds.

If a Policy is obtained, the obligations of the Bond Insurer are general obligations of the Bond Insurer, and in an event of default by the Bond Insurer, the remedies available may be limited by applicable bankruptcy law or other similar laws related to insolvency.

SECURITY FOR THE 2026 BONDS

General

The 2026 Bonds are payable solely from, and secured by a lien upon and pledge of, the Revenues on a parity basis with the lien and pledge securing Revenue Obligations issued pursuant to the Revenue Obligation Resolution, senior to (a) payments required to be made from or retained in the Revenue Fund to pay Operation and Maintenance Expenses, and (b) the payments into the Capital Improvement Fund heretofore established and continued under the Revenue Obligation Resolution (the "Capital Improvement Fund"). In the Revenue Obligation Resolution, the Authority has covenanted not to incur any indebtedness senior to the lien of the Revenue Obligations.

The Revenue Obligations, including the 2026 Bonds, are not indebtedness of the State, nor of any political subdivision thereof, and neither the State nor any of its political subdivisions are liable thereon, nor are they payable from any funds other than the Revenues of the Authority pledged to the payment thereof.

Additional series of Revenue Obligations may be issued without limitation and without compliance with any additional bonds test, provided there is no default under the Revenue Obligation Resolution. In addition, no debt service reserve fund is established under the Revenue Obligation Resolution. See APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION."

Rate Covenant

The Revenue Obligation Resolution provides that the Authority establish, maintain and collect rents, tolls, rates and other charges for power and energy and all other services, facilities and commodities sold, furnished or supplied through the facilities of the System which will be adequate to provide the Authority with Revenues sufficient: (a) to pay the principal of, premium, if any, and interest on the Revenue Obligations as and when the same become due and payable; (b) to make when due all payments which the Authority is obligated to make (i) into the Revenue Obligation Fund created under the Revenue Obligation Resolution, and (ii) into the Capital Improvement Fund pursuant to the Revenue Obligation Resolution; (c) to make all other payments which the Authority is obligated to make pursuant to the Revenue Obligation Resolution; (d) to pay all proper operation and maintenance expenses and all necessary repairs, replacements and renewals thereof; (e) to pay all taxes, assessments or other governmental charges lawfully imposed on the Authority or the Revenues thereof or payments in lieu thereof; and (f) to pay any and all amounts which the Authority may become obligated to pay from the Revenues of the System by law or by contract.

Certain Remedies

The Revenue Obligation Resolution provides that if the Authority violates or fails to perform any of its covenants or agreements contained in the Revenue Obligation Resolution for ninety (90) days after written notice of default is given to it by the Trustee or by a holder of any Obligation, then either the Trustee or the holders of not less than 25% in principal amount of the Obligations then Outstanding may, among other things, declare the principal of all the Obligations then Outstanding, and the interest accrued thereon, to be due and payable immediately. See APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION – Events of Default and Remedies under the Revenue Obligation Resolution."

Additional Indebtedness

Additional series of Revenue Obligations may be issued on a parity with Authority's Outstanding Revenue Obligations, including the 2026 Bonds, without limitation and without compliance with any additional bonds test, provided there is no default under the Revenue Obligation Resolution. The Revenue Obligation Resolution does not prohibit the issuance of obligations secured by a pledge of the Revenues junior and subordinate to the pledge securing the Revenue Obligations. In addition, the Authority may issue obligations secured by a pledge of revenues derived from separate utility systems not included in the System. See APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION – Separate Systems."

The approval of the JBRC may be required prior to the issuance of certain indebtedness of the Authority. See "THE AUTHORITY – Joint Bond Review Committee Approval."

Flow of Funds

The Authority covenants and agrees in the Revenue Obligation Resolution to pay into the Revenue Fund all Revenues received by the Authority, as promptly as practical after receipt thereof. The Revenue Fund is held in trust and administered by the Authority.

Moneys are disbursed by the Authority from the Revenue Fund in the following order:

1. Revenue Obligation Fund: To pay, when due, to the Trustee for deposit in the Revenue Obligation Fund an amount equal to principal, premium, if any, and interest on all the Obligations, including certain payments on Qualified Swaps, from time to time Outstanding as the same respectively become due and payable. Such amounts are required to be transferred by the Authority to the Trustee for deposit into the Revenue Obligation Fund no later than the business day immediately preceding the next date upon which an installment of principal (whether upon maturity or mandatory redemption), premium, if any, or interest falls due on the Obligations (or in immediately available funds on such due date), in an amount equal to such installment of principal, premium, if any, or interest then falling due on all Obligations then Outstanding.

2. Operating and Maintenance: To pay expenses of operation and maintenance.

3. Subordinated Debt: To pay, when due, amounts due and owing with respect to the payment of principal and interest on amounts issued under the Note Resolution (as defined herein), including Commercial Paper Notes and the Authority's payment obligations under the CP Reimbursement Agreements and the Revolving Credit Agreements.

4. Capital Improvement Fund: To pay during each Fiscal Year into the Capital Improvement Fund an amount at least equal to the amount which, together with the amounts deposited in the Capital Improvement Fund in the two immediately preceding Fiscal Years, will be at least equal to eight percent (8%) of the Revenues paid into the Revenue Fund in the three immediately preceding Fiscal Years. Permitted use of moneys in the Capital Improvement Fund is limited to payment of Capital Costs, as defined in the Revenue Obligation Resolution.

Any moneys remaining in the Revenue Fund each month after making the payments described above may be used by the Authority for any corporate purpose of the Authority. See APPENDIX B – "SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION" and "THE AUTHORITY – Outstanding Indebtedness – Subordinated Debt" herein.

Distributions to the State

As required by the Act, the Authority makes distributions to the State and payments in lieu of taxes ("PILOTs") to local governments and collects franchise fees on behalf of the municipalities.

Distributions to the State. The South Carolina Code provides that the Authority is to be operated for the benefit of the people of the State and requires that all net earnings of the Authority not needed for the prudent conduct and operation of its business or to pay the principal of and interest on its bonds, notes, or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others, be paid to the State Treasurer on a semiannual basis to be used to reduce the tax burdens on the people of the State. The Code further provides that the Authority is not prohibited from paying to the State each year up to one percent of its projected operating revenues, determined on an accrual basis, from the combined electric and water systems. The Authority's Act was amended in 2005 to include a one percent cap on the Authority's payments to the State Treasurer. A resolution was adopted by the Board on November 14, 2005, authorizing the one percent calculation, and since that time, the Authority has paid one percent of its projected annual operating revenues to the State Treasurer. Such payments totaled $18,961,000 for 2023, $19,420,000 for 2024, and $20,865,000 for 2025.

The South Carolina Office of Regulatory Staff (the "ORS") is authorized to bill the Authority for the costs associated with its oversight of the Authority performed pursuant to Act 90 of 2021 and any other relevant legislation, statute, or provision, provided that such costs do not exceed the amount of the costs authorized in the State's 2025-26 Appropriations Act. The ORS is authorized to expend up to $2,000,000 for oversight of the Authority in 2025-2026. The State's 2025-26 Appropriations Act allows the Authority to reduce its remittance of revenues to the State by the amount the Authority pays to the ORS for the costs incurred in the performance of its oversight of the Authority. Through December 31, 2025, the ORS has not billed the Authority, and the Authority has not reduced its remittance to the State for such oversight costs. The ORS has informed the Authority they will begin to bill for oversight in 2026. However, as the Authority will deduct these oversight costs from the annual payment to the State, there will be no material impact on the Authority's financial metrics.

The South Carolina Public Service Commission (the "SCPSC") is authorized, subject to approval by the Public Utilities Review Committee (the "PURC") of the SCPSC annual budget, to bill the Authority for the costs associated with its oversight of the Authority performed pursuant to Act 90 of 2021 and any other relevant legislation, statute, or provision, provided that such costs do not exceed the amount of the costs authorized in the State's 2025-2026 Appropriations Act. The State's 2025-2026 Appropriations Act allows the Authority to reduce its remittance of revenues to the State by the amount the Authority pays to the SCPSC for the costs incurred in the performance of its oversight of the Authority. Through December 31, 2025, the SCPSC has not billed the Authority, and the Authority has not reduced its remittance to the State for such oversight costs.

PILOTs. Under the Act, the PILOTs are subject to the Authority's payment of necessary operating expenses and annual debt requirements on bonds, notes, or other obligations at any time outstanding, and the discharge of all annual obligations arising under finance agreements with the United States, or any agency or corporation of the United States, and indentures under which bonds have been issued. The Authority made PILOTs of $5,023,263 for 2023, $5,273,825 for 2024, and $5,808,621 for 2025.

Franchise Fee. A franchise fee is a contractual fee the Authority remits to municipalities where it conducts business within their boundaries. This fee is billed each month to customers whose accounts are physically located within the city or town limits. The Authority then pays the money back to municipalities twice a year. The Authority paid $6,008,610 for 2023, $6,515,546 for 2024, and $6,943,921 for 2025.

The Authority's distributions to the State, PILOTs, and Franchise Fees totaled approximately $29,992,873 for 2023, $31,209,371 for 2024, and $33,617,542 for 2025.

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THE AUTHORITY

General

The Authority is a body corporate and politic created by the Act in 1934. The Authority's primary business operation is the production, transmission, and distribution of electrical energy, both wholesale and retail, to citizens of the State. The Authority is one of the nation's largest municipal wholesale utilities, whose electric system serves directly or indirectly approximately two million South Carolinians in all 46 counties of the State. The Authority began electric power operations in 1942.

Under the Act, the Authority is also authorized to construct, own and operate facilities to treat, transmit, distribute, and sell water at wholesale within the counties of Berkeley, Calhoun, Dorchester, and Orangeburg, and the Town of Santee, South Carolina. The Authority owns and operates the Lake Moultrie Regional Water System and the Lake Marion Regional Water System, two modern drinking water treatment systems serving over 260,000 people. The Lake Moultrie Regional Water System began commercial operation in October 1994, and the Lake Marion Regional Water System began commercial operation in May 2008. Each of the regional water systems is contractually required to be self-supporting.

Governance

The Act contains provisions governing the composition, qualifications, appointments, and duties of the Board. The Governor appoints the voting directors of the Board, and the State Regulation of the PURC screens appointees to determine whether they have the qualifications required by the Act. After successful screening, appointees must be confirmed by the State Senate. In making appointments to the Board, the Governor and the Senate, in its advice and consent capacity, must give due consideration to race, gender, and other demographic factors to assure nondiscrimination, inclusion, and representation to the greatest extent possible of all segments of the population of the State. *Ex officio* directors are appointed by Central's board, and within six months of appointment, the PURC must confirm they have the qualifications required by the Act. The Act describes the duties of directors and sets forth conditions by which a director may be held accountable for their actions or inactions as a director.

The Board consists of fourteen directors (twelve voting directors and two non-voting *ex officio* directors). The voting directors are as follows: one from each congressional district of the State; one from each of the counties of Berkeley, Horry, and Georgetown who reside in the territory of the Authority and are customers of the Authority and two from the State at large, one of whom must be chairman. Two of the voting directors must have substantial work experience within the operations of electric cooperatives or substantial experience on an electric cooperative board but must not serve as an employee or board member of an electric cooperative during their term as director of the Authority. One of these two voting directors must have substantial experience within the operations or board of a transmission or generation cooperative. The two *ex officio* non-voting directors are to be from Central, one of whom is the chairman of Central or their designee, and one of whom is a member of the Central board other than its chairman and is chosen by the Central board.

Voting directors serve for a term of four years, and *ex officio* members serve for a term of two years. Directors may continue to serve until a successor has been appointed and found qualified as provided for by the Act. Directors appointed to fill a vacancy on the Board serve for the unexpired portion of the term and until a successor is appointed, found qualified, and confirmed. A voting individual appointed and found qualified by the PURC while the State Senate is not in session may serve as a director in an interim capacity. Voting directors may be removed from office only for cause, and *ex officio* directors may be removed for cause or by the Central board. Directors may not be appointed for more than three consecutive full terms.

Each director is required to discharge their duties, in good faith, with the care an ordinarily prudent person in a like position would exercise under similar circumstances, and in a manner they reasonably believe to be in the best interests of the Authority, which involves a balancing of, among other things, preservation of the financial integrity of the Authority and its operations, the interest of the Authority's residential, commercial, and industrial retail customers in reliable, adequate, efficient, and safe service, at just and reasonable rates, regardless of customer class, and the exercise of the powers of the Authority set forth in the Act in accordance with good business practices and the requirements of applicable licenses, laws, and regulations.

The Act also contains provisions that establish an advisory board (the "Advisory Board") to assist the Board which is composed of the following officials of the State: the Governor, the Attorney General, the State Treasurer, the Comptroller General, and the Secretary of State. The Board is required to make annual reports to the Advisory Board, which reports must be submitted to the General Assembly by the Governor, in which full information as to all of the acts of said Board are given, together with financial statement and full information as to the work of the Authority.

The Advisory Board approves the hiring of the external auditors and sets the salary of the voting members of the Board. Any compensation package, severance package, payment, or other benefit conferred upon a director is required to be approved by the Agency Head Salary Commission of the State Fiscal Accountability Authority (the "Salary Commission").

Peter M. McCoy Jr. serves as the Chairman of the Board and the current Directors are listed below:

Name	Business	Residence	Term Expires	District
Peter M. McCoy Jr., *Chairman*	Attorney	Charleston	January 1, 2026[(1)]	At Large
David F. Singleton, *First Vice Chairman*	Business Executive	Myrtle Beach	January 1, 2025[(1)]	Horry County
John S. West, *Second Vice Chairman*	Attorney	Moncks Corner	January 1, 2027	Berkeley County
Charles S. Bennett II	Business Executive	Hilton Head	January 1, 2027	1st District
Kristofer D. Clark	Business Executive	Easley	January 1, 2024[(1)]	3rd District
Charles E. Dalton	Retired Business Executive	Greenville	January 1, 2026[(1)]	4th District
Brian C. Frerichs	Business Executive	Sumter	January 1, 2029	5th District
Stephen H. Mudge	Business Executive	Clemson	January 1, 2024[(1)]	At Large
Alyssa L. Richardson	Attorney	North Charleston	January 1, 2028	6th District
Stacy K. Taylor	Attorney	Chapin	January 1, 2026[(1)]	2nd District
Timothy M. Tilley	Business Executive	Georgetown	January 1, 2029	Georgetown County
Hugh L. Willcox, Jr.	Attorney	Florence	January 1, 2027	7th District
A. Berl Davis Jr.	Business Executive	Bluffton	July 13, 2025[(1)]	*Ex Officio*
Chad T. Lowder	Business Executive	St. Matthews	July 13, 2025[(1)]	*Ex Officio*

(1) The current Board seats have expired. These members will serve until a successor has been confirmed.

Executive Staff

The President and Chief Executive Officer of the Authority is appointed by the Board. Any compensation package, severance package, payment, or other benefit conferred upon the President and Chief Executive Officer of the Authority must first be reviewed and approved by the Salary Commission. Additionally, any employment contracts or retention contracts that last longer than five years, and all contract extensions, must be reviewed by the Salary Commission. The Authority's executive staff is appointed by the President and Chief Executive Officer with the approval of the Board. The President and Chief Executive Officer and executive staff are listed in the following table.

Name	Position	Utility Experience
Jimmy D. Staton	President and Chief Executive Officer	42 years
Michael J. Finissi	Deputy Chief Executive Officer and Chief Operating Officer	41 years
Carmen H. Thomas	Vice President, Chief Legal Officer and General Counsel	21 years
Tamara R. Wilson	Vice President and Chief Financial Officer	24 years

Jimmy D. Staton, the Authority's President and Chief Executive Officer, joined the Authority on March 1, 2022. Prior to joining the Authority, Mr. Staton served as President and Chief Executive Officer of Southern Star Corp., a leading transporter of natural gas in the Midwest. He also served as Executive Vice President for NiSource, one of the largest fully regulated utility companies in the United States with approximately 3.5 million natural gas customers and 500,000 electric customers across seven states, as Senior Vice President for Dominion Resources Inc., and as President of Asset Operations for Consolidated Natural Gas Corp. prior to its acquisition in 2000 by Dominion Resources. He received a Bachelor of Science degree in Petroleum Engineering from Louisiana State University in 1983.

Michael J. Finissi, the Authority's Deputy Chief Executive Officer and Chief Operating Officer, joined the Authority on April 3, 2023. He has extensive experience managing generation and transmission operations and construction for electric and gas utilities in the U.S. and Canada, and he has accumulated a strong safety record across the areas he has managed. He has served as an executive for several utilities in the nuclear, electric, and natural gas segments, including Bruce Power in Ontario, NiSource Inc. in Ohio, NIPSCO in Indiana, and American Electric Power. He received a Bachelor of Science in Electrical and Electronics Engineering from The Ohio State University and a Master of Business Administration from Capital University. He completed the University of Virginia Darden School of Business Executive Program, and he is a licensed professional engineer and senior reactor operator.

Carmen H. Thomas, the Authority's Vice President, Chief Legal Officer and General Counsel, joined the Authority on January 6, 2025. She had previously represented the Authority in a variety of legal matters over the previous 17 years, most of that as a partner with external counsel, Nelson Mullins Riley & Scarborough, LLP. At Nelson Mullins, Thomas was responsible for resolving disputes and regulatory issues in the energy, manufacturing, financial services, and technology sectors. She received a Bachelor of Arts from the University of South Carolina Honors College in journalism and mass communications with a cognate in political science, a Master of Public Administration from the University of South Carolina focused on environmental resource management and local government, and a law degree from the University of South Carolina. She has been a member of the South Carolina Bar Association since 2007. Prior to being a lawyer, Thomas worked in the S.C. Senate and House of Representatives, the State Energy Office, and the S.C. Department of Commerce.

Tamara R. Wilson, the Authority's Vice President and Chief Financial Officer, joined the Authority on October 13, 2025. Her expertise spans both regulated and deregulated energy companies and private and public companies, with experience across natural gas, power, and solar sectors. Prior to joining the Authority, Ms. Wilson served as Chief Financial Officer of Stellex Power Line Opco, LLC, and prior to that role, as Chief Financial Officer and Executive Vice President of Rokstad Power Holdings; Executive Vice President, Chief Financial Officer, and Chief Growth Officer for Southern Star Natural Gas Pipeline; Chief Finance and Risk Officer for IGS; and President/Chief Financial Officer for Vectren Retail, LLC. She has held the Certified Public Accountant credential. She received her Bachelor of Science degree in Accounting from the University of Evansville.

Staff

The Authority had 1,688 employees as of December 31, 2025. Authority employees are members of a contributory State retirement plan administered by the South Carolina Public Employee Benefit Authority ("PEBA"). As of December 31, 2024, the Authority's net pension liability under the plan was $279.6 million. For a further description of the retirement plan, including funding status, see APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS – Note 11 – Retirement Plans."

The Authority also participates in an agent multiple-employer defined benefit healthcare plan whereby PEBA provides other postemployment benefits ("OPEB") consisting of certain health and life insurance for eligible retired employees of the Authority. As of December 31, 2024, the Authority's net liability under the OPEB plan was $161.2 million. For a further description of the OPEB plan, including funding status, see APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS – Note 12 – Other Postemployment Benefits (OPEB)."

The Authority's employees do not participate in any unions, and the Authority believes that its labor relations are good.

Joint Bond Review Committee Approval

The Act requires that prior to the issuance by the Authority of its (i) bonds, (ii) notes, or (iii) other indebtedness, including any refinancing that does not achieve a savings in total debt service, the Authority is required to request the approval of the JBRC. Upon receipt of such request, the JBRC may approve, reject, or modify the debt issuance proposed by the Authority. If the JBRC does not approve, reject, or modify the Authority's request for approval of a proposed debt issuance within sixty days, the issuance is deemed approved. A proposed debt issuance that receives JBRC approval may be issued across multiple series and over a three-year period.

On January 29, 2025, the JBRC approved the issuance of up to $750 million aggregate principal amount of debt to fund capital expenditures. As of the date hereof, $150 million remains available to be issued under that approval. On October 7, 2025, the JBRC approved the debt issuance of up to $570 million aggregate principal amount of debt to refinance the Cook Rate Freeze Exceptions, which debt is expected to be issued before the end of 2026 to pay down bank facility debt associated with the Cook Rate Freeze Exceptions. On December 2, 2025, the JBRC approved the issuance of up to $700 million aggregate principal amount of debt to fund capital expenditures for certain generation resources. A portion of this authorization will be included in the 2026A and 2026B bond issuances, with the remainder expected to be issued over a three-year period. The authorization for the Series 2026 Bonds was approved at meetings of the JBRC on January 29, 2025 and December 2, 2025. The Authority expects to request JBRC approval of additional debt to fund capital expenditures during 2026 and 2027. There can be no assurance that any such approval will be obtained or that any such additional debt will be issued. See "THE AUTHORITY – Capital Improvement Program and Future Financings."

JBRC approval is not required for the issuance of refunding bonds that achieve savings in total debt service or for the issuance of short-term or revolving-credit debt for the management of day-to-day operations and financing needs of the Authority.

In addition, with the exception of encroachment agreements, rights of way, or lease agreements made by the Authority for property within the FERC project boundary, a transfer of any interest in real property by the Authority, regardless of the value of the transaction, requires approval, rejection, or modification by the JBRC, and the Authority is required by September 1st of each year, to provide an annual report to the JBRC regarding every transaction involving an interest in real property executed during the preceding twelve months.

Outstanding Indebtedness

Senior Debt

Pursuant to the Act, the Board adopted the Revenue Obligation Resolution providing for the issuance of the Authority's Revenue Obligations. As of January 2, 2026, the Authority had approximately $7.539 billion in aggregate principal amount of Revenue Obligations outstanding under the Revenue Obligation Resolution, of which $3.423 billion was issued by the Authority to finance the costs of the Nuclear Units.

Subordinated Debt

The Revenue Obligation Resolution provides that the Authority may issue obligations that are secured by a lien upon and pledge of Revenues junior to the lien and pledge securing Revenue Obligations. Pursuant to this authority, the Board has by resolution (the "Note Resolution") authorized the issuance of (A) subordinate commercial paper notes (the "Commercial Paper Notes") so long as the aggregate principal amount of the Commercial Paper Notes outstanding at any one time does not exceed the lesser of (i) twenty percent (20%) of the aggregate Authority debt and alternative variable rate financing obligations outstanding as of the last day of the most recent Fiscal Year for which audited financial statements of the Authority are available, or (ii) the aggregate unused commitment under any revolving credit agreements and alternative variable rate financing agreements; and (B) alternative variable rate financing obligations so long as the aggregate principal amount of the alternative variable rate financing obligations and Commercial Paper Notes outstanding at any one time does not exceed twenty percent (20%) of the aggregate Authority debt (including Commercial Paper Notes, revolving credit notes, and alternative variable rate financing obligations) outstanding as of the last day of the most recent Fiscal Year for which audited financial statements of the Authority are available.

Pursuant to the Note Resolution, the maximum amount of alternative variable rate financing obligations and Commercial Paper Notes that may be outstanding at any time is currently $1.545 billion.

Commercial Paper Notes. In accordance with the terms of the Note Resolution, the Board has authorized the issuance of Commercial Paper Notes currently consisting of the Subordinate Revenue Notes, Tax-Exempt CP Sub-Series A and Taxable CP Sub-Series AA, and the Subordinate Revenue Notes, Tax-Exempt CP Sub-Series B and Taxable CP Sub-Series BB. The payment of the principal and interest on the Commercial Paper Notes when due is supported by two irrevocable direct pay letters of credit issued by Barclays Bank pursuant to the CP Reimbursement Agreements on the related sub-series of Commercial Paper Notes. The Authority may issue up to $400 million aggregate principal amount of Commercial Paper Notes supported by the letters of credit under the CP Reimbursement Agreements, the proceeds of which may be used for any lawful corporate purposes, including to pay principal of and interest on maturing Commercial Paper Notes. The Barclays Bank letters of credit are scheduled to expire on the dates listed in the following table.

Irrevocable Direct Pay Letters of Credit
and CP Reimbursement Agreements
(Dollars in Thousands)
(as of January 2, 2026) (unaudited)

Facility	Capacity	Unused Capacity	Expiration Date
Barclays Bank Series A/AA	$200,000	$24,183	September 15, 2028
Barclays Bank Series B/BB	200,000	82,834	September 17, 2027
Total	$400,000	$107,017	

[Remainder of page intentionally left blank]

Revolving Credit Agreements. The Authority is party to five revolving credit agreements (collectively, the "Revolving Credit Agreements") with each of the following banks: Bank of America, JP Morgan Chase Bank, National Association ("JP Morgan"), TD Bank, National Association ("TD Bank"), Truist Bank, and Wells Fargo Bank, National Association ("Wells Fargo"). The Revolving Credit Agreements, as of January 2, 2026, provided the Authority with borrowing capacity in an aggregate principal amount of up to $1.1 billion, as described in the following table. Amounts borrowed by the Authority under the Revolving Credit Agreements may be used for any lawful corporate purposes.

Revolving Credit Agreements
(Dollars in Thousands)
(as of January 2, 2026) (unaudited)

Bank	Capacity	Unused Capacity	Expiration Date
Bank of America	$250,000	$ 10,400	March 1, 2029
JP Morgan	250,000	63,225	March 31, 2028
TD Bank	200,000	200,000	June 30, 2028
Truist Bank	300,000	299,710	January 4, 2030
Wells Fargo	100,000	11,900	March 25, 2027
Total	$1,100,000	$585,235	

The Authority's obligations to repay loans advanced under the CP Reimbursement Agreements and the Revolving Credit Agreements are each secured on a *pari passu* basis by a lien upon and pledge of Revenues which lien and pledge is junior to the lien and pledge securing the Revenue Obligations, including the 2026 Bonds.

Capital Improvement Program and Future Financings

The Authority regularly reviews and updates its capital improvement program to reflect currently anticipated capital projects and expenditures. With regard to planning and development of its power system, including major utility facilities, the Authority is required to submit an integrated resource plan every three years to the SCPSC for its review and approval, with updates to the plan submitted annually in the intervening years. See "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES – Integrated Resource Planning – *Integrated Resource Plans*."

On May 1, 2025, the SCPSC approved the 2024 Integrated Resource Plan Update under Order No. 2025-244. The Authority's current capital improvement program includes a future power supply plan with an initial set of changes to the Authority's generation and transmission systems based on certain assumptions outlined in the Authority's 2025 Integrated Resource Plan's Annual Update, filed with the SCPSC on September 16, 2025 (the "2025 Integrated Resource Plan"). See "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES – Integrated Resource Planning" for additional information on the Authority's IRPs.

The capital improvement program also reflects requirements related to FERC relicensing expenditures, expenditures necessary to maintain compliance with environmental regulations, and general improvements to the Authority's system, including improvements to existing power supply facilities, extensions of and improvements to the transmission and distribution systems, and other general improvements.

Current projections estimate the total cost of the capital improvement program for 2026 through 2028 at approximately \$3.5 billion, comprised of approximately \$1.4 billion for new generating resources, \$1.1 billion for transmission projects to support system growth and reliability, \$800 million for general improvements to the System, \$110 million for environmental compliance expenditures for the electric system, \$10 million related to FERC relicensing, and \$85 million for the Regional Water Systems capital improvement program, which includes \$45 million for compliance with regulation of PFAS. See "REGULATORY MATTERS" for more information on compliance with regulations for the Regional Water Systems.

The Authority funds its capital improvement program through a combination of internally generated funds, contributions in aid of construction, and other grants, the issuance of Commercial Paper Notes, loans under the Revolving Credit Agreements, and the incurrence of other short-term and long-term debt, as determined by the Authority. The Authority's current projections reflect the issuance of approximately \$2.4 billion of long-term debt to fund certain capital improvement projects through 2028.

As a utility not subject to Sections 205 and 206 of the Federal Power Act, FERC does not regulate the rates, terms, or conditions of the Authority's Open Access Transmission Tariff ("OATT"). Similar to FERC's pro-forma OATT, the Authority's OATT, as adopted by its Board, provides that the Authority will reimburse the costs associated with network upgrades to interconnection and transmission customers when such upgrades are required to integrate interconnection and transmission projects onto the Authority's transmission system. Under the provisions of the Authority's OATT, transmission and interconnection customers are required to fully front the costs of such network upgrades. However, once the transmission or interconnection project associated with the network upgrades has been placed into commercial service, the Authority shall undertake to reimburse the costs of the network upgrades. Such reimbursement may be made by the Authority as (i) a lump-sum payment, (ii) over a term of up to twenty years with interest, or (iii) in certain cases, through transmission service credits. The Authority is aware of multiple developer-led interconnection projects that may seek interconnection to the Authority's transmission system in the coming years that have network upgrades identified as part of the interconnection study process. Due to the preliminary nature of these studies and the customer's ability to withdraw from the study process, at this time, the Authority is unable to predict the total cost of these network upgrades. However, if a significant number of these projects move forward, the costs could be material, and such costs are not currently reflected in the projections related to the Authority's capital improvement program.

Regional Water Systems

The Authority owns and operates two drinking water treatment systems serving over 260,000 people (collectively, the “Regional Water Systems”): (i) the Lake Moultrie Regional Water System, with rights to its production capacity of 40 million gallons per day (“MGD”) owned by the Lake Moultrie Water Agency (the “Moultrie Agency”), and (ii) the Lake Marion Regional Water System, with rights to its production capacity of 8.5 MGD owned by the Lake Marion Regional Water Agency (the “Marion Agency”).

The Authority supplies both agencies with potable water, and both agencies purchase and pay for the entire output of the respective Regional Water Systems. The Authority may issue debt to pay for the cost to construct and upgrade the Regional Water Systems. Each agency reimburses the Authority for raw water taken from Lakes Moultrie and Marion at an established rate that compensates the electric system for the loss of potential energy at the Jefferies Hydroelectric Station. Rates and charges are maintained at levels sufficient for the Authority to pay all of the costs for capital expenditures, debt service, and current expenses charged to the Regional Water Systems.

The current terms of the Authority’s contracts with the Moultrie Agency and the Marion Agency expire on October 2, 2027 and November 1, 2027, respectively. Under certain material events, such as termination of the contract with the Marion Agency and the sale of the water system under the contract with the Moultrie Agency, each agency has the right to purchase their respective Regional Water System for a price equal to the amount required to redeem the outstanding debt allocable to such agency and the right to withdraw the same volume of water from the lakes as their respective Regional Water System.

Insurance

The Revenue Obligation Resolution requires that the Authority shall keep, or cause to be kept, its properties and the operations thereof insured to the extent available at reasonable cost with responsible insurers against risks of direct physical loss, damage to, or destruction. Such insurance must be at least to the extent that similar insurance is usually carried by utilities operating like properties against accidents, casualties, or negligence, including liability insurance and employer’s liability. However, while any contractor engaged in constructing facilities is fully responsible therefor, the Authority shall not be required to procure or maintain such insurance.

Cybersecurity

Like many other large public and private entities, the Authority relies upon a complex technology environment to conduct its operations and faces multiple cybersecurity threats on its digital networks and systems (collectively, “Systems Technology”). As the Authority’s electricity and water businesses fall within the critical infrastructure sectors identified in Presidential Policy Directive 21: Critical Infrastructure Security and Resilience (“PPD-21”), and virtually all the Authority’s operations are dependent in some manner upon the Systems Technology, the loss or impairment of the Systems Technology could have a serious adverse effect on the Authority’s customers and communities. Cybersecurity incidents could result from unintentional events or from deliberate attacks by unauthorized entities and individuals attempting to gain access to the Systems Technology for inappropriate purposes, including misappropriating assets or information or causing operational disruption and damage. A successful physical or cyber-attack could lead to outages, failure of operations of all or portions of the Authority’s businesses, damage to key components and equipment, and exposure of confidential customer, employee, or corporate information.

To mitigate the risk to the Authority’s business operations of damage from cybersecurity incidents, the Authority invests in multiple forms of cybersecurity and physical safeguards. While the Authority’s cybersecurity and physical safeguards are periodically tested, no assurance can be given by the Authority that such measures will protect against cybersecurity attacks, and any breach could damage the Systems Technology and cause material disruption to the Authority’s finances or operations. In addition, the failure to secure the Authority’s operations from such physical and cyber events may cause reputational damage to the Authority. The costs of remedying any such damage or protecting against future attacks could be substantial. Furthermore, cybersecurity breaches could expose the Authority to material litigation and other legal risks, which could cause the Authority to incur material costs, and the cyber and property insurance currently carried by the Authority may not be adequate to respond to these events. As a result, the Authority's financial condition, results of operations, and cash flows may be adversely affected.

The Authority maintains awareness of emerging cybersecurity threats through open-source, commercial, and industry threat intelligence sources. Based upon this information and observations of cybersecurity activity, the Authority proactively updates its cybersecurity strategy to address increases in scope, complexity, and frequency of identified threat vectors. The Authority evaluates its cybersecurity program against industry and federal standards on a periodic basis and engages third party firms to perform independent testing of the Authority's cybersecurity program's effectiveness.

The Authority has and will continue to implement industry practices and maintain vigilance in ensuring that the security posture of the organization evolves commensurately to identified risks. To date, the Authority has not detected any cybersecurity or physical incidents that would have had a significant effect on the Authority's operations, financial condition, customers, or employees.

Sustainability Initiatives

The Authority has developed and is implementing an enterprise-wide strategic plan for sustainability in business practices and corporate responsibility. The Authority also is engaged in transition efforts related to the future retirement of its coal-fired generation and the stakeholders impacted thereby. The Authority's sustainability efforts go hand in hand with its corporate vision and mission and are guided by four key areas and objectives:

1. People – workforce of tomorrow;

2. Perception – trusted partner and advisor to our customers, government officials, and the citizens of South Carolina;

3. Performance – right-sized, reliable and resilient, diverse, and sustainable; and

4. Profitability – affordable competitive excellence.

The Authority continues its commitment to sustainable practices that prioritize long-term economic performance; environmental stewardship; reliable, affordable energy and water; effective corporate governance; corporate responsibility; and transparency. Additional information about its efforts is included in its 2024 Sustainability Report which is available on the Authority's website at https://www.santeecooper.com/about/sustainability-report/. *No statement or information on the Authority's website is incorporated by reference into this Official Statement.*

FINANCIAL INFORMATION

The following selected financial information is provided below: (i) a narrative summary of the Authority's outstanding debt and liquidity as of January 2, 2026; (ii) selected unaudited financial information for the nine months ending September 30, 2025 and September 30, 2024, accompanied by management's comments on such financial information; (iii) a comparison of actual results versus budget for selected unaudited financial information for the nine months ending September 30, 2025, accompanied by management's comments on such financial information; (iv) a summary of operating results for the five years ending December 31, 2020 through December 31, 2024; (v) selected audited financial information for calendar years 2024 and 2023 accompanied by management's comments on such financial information; (vi) a table showing combined statements of net position for the periods ending September 30, 2025 and December 31, 2024 and (vii) a narrative description of the Cook Rate Freeze Exceptions, the use of regulatory accounting for the Cook Rate Freeze Exceptions, and the funding of the Cook Deferred Expenses (as defined herein) associated with such Cook Rate Freeze Exceptions.

Recent Financial Information

Debt. As of January 2, 2026, the Authority had approximately $8.3 billion of outstanding indebtedness consisting of: (i) $7.539 billion in aggregate principal amount of Revenue Obligations under the Revenue Obligation Resolution, of which $3.423 billion ($2.709 billion tax-exempt and $0.714 billion taxable) was issued to finance costs of the Nuclear Units; (ii) $292.983 million aggregate principal amount of Commercial Paper Notes issued under the Note Resolution; and (iii) $514.765 million of loans issued under the Note Resolution and the Revolving Credit Agreements. For additional details on the Authority's outstanding indebtedness, its bank facilities, and plans to issue additional indebtedness, see "INTRODUCTION – Outstanding Parity and Subordinated Indebtedness" and "THE AUTHORITY – Outstanding Indebtedness" and "– Capital Improvement Program and Future Financings."

As of January 2, 2026, the aggregate principal amount of the Authority's variable rate debt totaled $918.0 million (consisting of the Commercial Paper Notes, the loans under the Revolving Credit Agreements and the 2019A Bonds), representing 11% of the Authority's aggregate outstanding indebtedness.

Interest Rate Swaps. The Authority has no interest rate swaps.

Liquidity. The Authority's liquidity consists of its funds on hand and funds in various unrestricted reserves. As of September 30, 2025, the Authority had $535.9 million of available cash and unrestricted reserves that can be used to meet unexpected costs (comprised of $202.6 million of unrestricted cash and cash equivalents, and $333.3 million of unrestricted investments). In addition, as of January 2, 2026, the Authority had $107.0 million of unused Commercial Paper Note capacity supported by the letters of credit under the CP Reimbursement Agreements described herein, and $585.2 million of unused loan capacity under the Revolving Credit Agreements. See "INTRODUCTION – Outstanding Parity and Subordinated Indebtedness" and "THE AUTHORITY – Outstanding Indebtedness" and "– Capital Improvement Program and Future Financings."

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Selected Recent Financial Information

Nine Months Ended September 30, 2025 and 2024

	Nine Months Ended September 30, (Unaudited) (Dollars in Thousands)			
	2025	**2024**	**Variance**	**%**
Operating revenues	$1,781,629	$1,472,482	$309,147	21
Less: Operating expenses	1,413,855	1,258,625	155,230	12
Operating income	$ 367,774	$ 213,857	$153,917	72
Non-operating revenues (expenses):				
Interest charges	(266,470)	(221,959)	(44,511)	(20)
Costs to be recovered from future revenue (expense)	3,019	(197)	3,216	1,632
Other non-operating income (expenses)	33,284	27,508	5,776	21
Income before transfers	137,607	19,209	118,398	616
Capital contributions and transfers	(20,865)	(19,420)	(1,445)	(7)
Change in net position	116,742	(212)	116,954	55,167
Total net position – beginning	$2,082,620	$2,250,352	$(167,732)	(7)
Total net position – ending	$2,199,362	$2,250,140	$(50,778)	(2)

Operating revenues for the nine months ended September 30, 2025, totaled approximately $1,781.6 million, a $309.1 million, or 21%, increase. The increase was driven primarily from higher heating/cooling degree days (8%) resulting from colder weather in January and March 2025, and warmer weather in July 2025 as compared to the same periods last year, as evidenced by exceeding the system peak multiple times in July 2025.

Operating expenses increased $155.2 million or 12%. The increase was primarily attributable to higher fuel and purchased power ($94.2 million) resulting from higher kWh sales and higher gas, coal, and market prices compared to the same period last year. Transmission constraints contributed to elevated market prices. Another contribution is lower credits to fuel and purchased power ($29.2 million) from the Cook Exceptions Regulatory Asset due to the amortization of the Cook settlement regulatory asset beginning in July 2025. Additional increases were provided by: (i) higher non-fuel generation ($8.0 million) due to: (a) higher Cross and Winyah repetitive maintenance/technical services; and (b) higher Cross and Winyah outage expenses; offset by (c) lower summer nuclear expenses due primarily to lower outage expenses; and (d) lower Rainey outages expenses; (ii) higher administrative and general expenses ($7.9 million) primarily due to lower Cook Rate Freeze Exceptions credits, higher human resources management expenses, and higher Technology Services subscription expenses; (iii) higher depreciation expense ($6.2 million) due to assets placed into service and asset retirements in the previous year; (iv) higher transmission expenses ($4.8 million) primarily due to higher outside transmission expenses; (v) higher distribution expenses ($3.8 million) primarily due to timing differences in clearing distribution rights-of-ways and general substation and overhead line maintenance costs.

Interest charges increased by $44.5 million primarily attributable to higher interest on long-term debt from the 2024 A & C new money bond issues in July 2024, the 2025 A & C new money bond issues in 2025, an additional increase resulting from the net effect of amortizing the Cook settlement regulatory asset in 2025, and the recording of credits from the Cook settlement regulatory asset in 2024.

Costs to be Recovered from Future Revenues ("CTBR") is a non-operating and non-cash income (expense) account. Higher depreciation on debt funded assets over principal payments on debt results in income, while higher principal payments on debt over depreciation results in expense. For the nine months ended September 30, 2025, CTBR expense decreased $3.2 million, or 1,632%, due to lower CTBR depreciation in the current year.

Other non-operating income increased approximately $5.8 million primarily due to higher nuclear equipment sales, higher interest income, an increase resulting from the recording of the Authority's patronage balance in a member-owned electrical supplier, and an increase in the fair market value of investments offset by higher year over year nuclear asset amortization, and lower gains associated with the Authority's investment in The Energy Authority ("TEA").

The $1.4 million variance in capital contributions and transfers represents an increase in dollars paid to the State. This payment is based on a percentage of total projected revenues which were higher in the 2025 budget as compared to 2024.

As a result of the above variances, the change in net position was a $116.7 million increase for the nine months ended September 30, 2025, a $117.0 million increase from the change in net position that occurred for the nine months ended September 30, 2024.

As a result of the above variances, net position totaled approximately $2.2 billion, a $50.8 million decrease, compared to September 30, 2024.

Nine Months Ended September 30, 2025 Compared to Budget

Nine Months Ended September 30, 2025
(Unaudited) (Dollars in Thousands)

	Actual	Budget	Variance	%
Operating:				
Operating revenues	$1,781,629	$1,727,176	$ 54,453	3
Less: Operating expenses	1,413,855	1,369,452	44,403	3
Operating income	$ 367,774	$ 357,724	$ 10,050	3
Non-operating revenues (expenses):				
Interest charges	(266,470)	(269,258)	2,788	1
Costs to be recovered from future revenue (expense)	3,019	19,206	(16,187)	(84)
Other non-operating income (expenses)	33,284	(7,842)	41,126	524
Income before transfers	137,607	99,830	37,777	38
Capital contributions and transfers	(20,865)	(20,865)	0	0
Change in net position	$ 116,742	$ 78,965	$ 37,777	48

Operating revenues for the nine months ended September 30, 2025, were higher than budgeted by $54.5 million primarily due to increased fuel revenues, due to higher-than-budgeted fuel and purchased power costs. Also contributing to the increase is higher than budget off system sales. An additional increase was driven by higher-than-expected energy sales in January, July, and August, along with strong summer demand sales. These gains were partially offset by the timing of the 2025 rate implementation and lower industrial contract demand.

Operating expenses were higher than projected by $44.4 million due to higher: (i) fuel and purchased power ($56.1 million) resulting from higher kWh sales and higher gas, coal, and energy market prices compared to budget. Key contributors were Winter Storm Enzo, record heat in June/July, and increased use of coal units partly due to transmission constraints; (ii) non-fuel generation ($4.4 million), primarily due to (a) higher Cross and Winyah repetitive maintenance, offset by (b) lower Fossil & Hydro management repetitive maintenance due to reserve used towards Cross and Winyah repetitive maintenance, no battery storage operating and maintenance expenses with the deferral of this project, and the timing of outside contract services, (c) lower expenses associated with Winyah due to less variable operations contributed by less run time and lagging limestone expenses, and Cherokee operations due to timing and less outside contract services, and (d) lower nuclear expenses due to lower labor and contract services which are primarily timing driven. These increases were offset by: (i) lower depreciation expense ($8.2 million) from timing associated with assets placed into service; and (ii) lower administrative and general ($6.3 million), primarily due to (a) lower than projected Technology Services, due to timing of cash flows, which are expected to be on budget by year-end; and (b) lower operating and maintenance costs for the Nuclear Units due to a consulting contract that was terminated, and site maintenance payments lower than budgeted.

Interest charges were lower than budgeted by $2.8 million due primarily to lower debt related amortization expenses than budgeted.

For the nine months ended September 30, 2025, CTBR revenue was lower than budgeted due primarily to timing differences associated with lower than projected CTBR depreciation and timing of when debt funded capital projects have been placed into service during 2025.

Other non-operating income was $41.1 million higher than projected due to higher than projected nuclear equipment sales, an increase in the fair value of investments, an increase due to the recording of our patronage balance in a member-owned electrical supplier, higher TEA gains, higher interest income, and higher miscellaneous land sales offset by lower than projected Camp Hall sales and higher than projected nuclear asset amortization.

As a result of the variances noted above, the change in net position was $37.8 million higher than budgeted.

Historical Annual Operating Results

A summary of the Authority's revenues available for debt service, lease payments, and other purposes and debt service coverage ratios for years ending December 31, 2020, through 2024 is set forth below:

Fiscal Year Ending December 31,
(Dollars in Thousands)

	2024	**2023**	**2022**	**2021**	**2020**
Operating Revenues	$1,916,851	$1,850,603	$1,949,050	$1,765,785	$1,627,427
Other Income	16,691	16,939	6,751	2,075	3,216
Total	1,933,542	1,867,542	1,955,801	1,767,860	1,630,643
Less: Operating Expenses (less depreciation)[1]	1,493,654	1,157,367	1,400,937	1,237,211	1,018,691
Revenues Available for Debt Service and Other Purposes	439,888	710,175	554,864	530,649	611,952
Debt Service on Revenue Obligations[2]	402,628	363,465	428,426	414,961	419,089
Balance Available for Other Purposes	$37,260	$346,710	$126,438	$115,688	$192,863
Debt Service Coverage, including Cook Deferred Expenses[3]	1.09x	1.95x	1.29x	1.27x	1.46x
Debt Service Coverage, excluding Cook Deferred Expenses[3]	1.28x	1.22x	0.46x	N/A	N/A

(1) Operating expenses were increased by $92.6 million in 2024 as a result of the Cook Exceptions Regulatory Asset write down related to the Exceptions Agreement and reduced by $243.2 million in 2023 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset.

(2) Debt Service was reduced by $17.5 million in 2024 and $23.3 million in 2023 due to the deferral of the Cook Deferred Expenses to the Cook Exceptions Regulatory Asset. The Revenue Obligation Resolution provides for debt service on Revenue Obligations to be paid from Revenues prior to payments for operating and maintenance expenses. See "SECURITY FOR THE 2026 BONDS – Flow of Funds."

(3) Calculation of coverage excludes debt service on Commercial Paper Notes and loans under the Revolving Credit Agreements and is prior to distributions to the State.

Debt Service Coverage. The Authority's 2024 debt service coverage, including Cook Deferred Expenses, was 1.09x. The decrease in debt service coverage from 2023 to 2024 was largely attributable to the Cook Exceptions Regulatory Asset write down in the current year related to the Exceptions Agreement. For further information, see APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS."

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Management's Discussion of Selected Historical Annual Financial Information

Calendar Year 2024 and 2023

The following table sets forth selected financial information of the Authority for calendar years 2024 and 2023.

	Calendar Year (Dollars in Thousands)			
	2024	**2023**	**Variance**	**%**
Operating:				
Operating revenues	$1,916,851	$1,850,603	$66,248	4
Operating expenses	1,764,307	1,429,528	334,779	23
Operating income	$152,544	$421,075	$(268,531)	(64)
Non-operating revenues (expenses):				
Interest charges	(325,044)	(315,045)	(9,999)	(3)
Costs to be recovered from future revenue (expense)	232	(8,433)	8,665	103
Other non-operating income (expenses)	23,956	37,797	(13,841)	(37)
Income before transfers and Special Item	(148,312)	135,394	(283,706)	(210)
Capital contributions, transfers, and Special Item	(19,420)	(18,961)	(459)	(2)
Change in net position	$(167,732)	$116,433	$(284,165)	(244)
Total net position – beginning	2,250,352	2,133,919	116,433	5
Total net position – ending	$2,082,620	$2,250,352	$(167,732)	(7)

Comparing 2024 to 2023, operating revenues increased $66.2 million (4%), primarily driven by higher demand usage and energy sales of $33.5 million and $15.9 million, respectively. The impacts were largely due to higher cooling degree days (9%) resulting from warmer weather than the previous year. Other factors causing the increase included higher: (i) fuel rate revenues of $10.9 million; (ii) off system sales of $10.2 million; and (iii) other smaller revenue adjustment increases of $3.8 million between the two periods. Offsets to this were provided by lower energy related fixed cost rates and O&M rate revenues of $4.8 million and $2.8 million, respectively. For comparison, energy sales for 2024 and 2023 were 27.2 million megawatt hours ("MWhs") and 26.2 million MWhs, respectively.

Operating expenses for 2024 increased $334.8 million (23%) as compared to 2023. The major causes were higher fuel and purchased power resulting from lower fuel and purchased power credits of $302.3 million in the current year as compared to prior year, due to the Cook Exceptions Regulatory Asset write down in the current year related to the Exceptions Agreement. (see Note 15- Subsequent Events) Purchased power increased $20.4 million due to replacement energy for outages and lower market prices as compared to prior year. These increases were offset by lower fuel of $53.1 million from outages and a less expensive energy mix versus prior year. Additional increases were: (i) higher non-fuel generation, which showed an increase of $33.5 million from the Cook Exceptions Regulatory Asset write down in the current year related to the Exceptions Agreement, and higher expenses associated with Winyah, Cherokee, and Rainey outages, increased Cross and Winyah repetitive maintenance and tech services, and increased Cherokee operations expenses. These increases in non-fuel generation were offset by lower expenses associated with gypsum processing due to underruns; (ii) administrative and general increased $21.5 million primarily due to the Cook Exceptions Regulatory Asset write down in the current year related to the Exceptions Agreement, and increased operational expenses due to securitization costs previously incurred to evaluate potential debt securitization being moved to O&M, as well as increased expenses associated with grant administration, and environmental services; and (iii) transmission increased $8.6 million primarily from higher outside transmission costs. Other small changes netted to the remaining variance.

Interest charges increased $10.0 million, resulting primarily from higher long-term debt interest of $9.1 million from additional revolving credit agreement (RCA) draws, the 2024 A & C new money bond issues, and lower interest expense credits of $5.8 million due to the Cook Exceptions Regulatory Asset write down in the current year related to the Exceptions Agreement. Somewhat offsetting this was an adjustment to customer deposit interest expense of $4.0 million.

For the year ended December 31, 2024, CTBR expense was lower year over year by $8.7 million because of higher CTBR depreciation related to debt funded assets in the current year.

Other non-operating income decreased $13.8 million, resulting primarily from higher amortization of the nuclear regulatory asset of $14.6 million, resulting from the 2024 B Refunding, a decrease in the fair value of investments of $3.5 million, and lower Camp Hall sales of $2.7 million. Offsetting these increases were higher nuclear equipment sales of $7.0 million.

The $459,000 variance in capital contributions and transfers represents an increase in dollars paid to the State. This payment is based on a percentage of total projected revenues which were higher in the 2024 budget as compared to 2023.

The change in net position totaled negative $167.7 million, a $284.2 million or 244% decrease from the $116.4 million increase in net position that occurred from 2022 to 2023.

As a result of the variances above, total net position was approximately $2.1 billion, a $167.7 million decrease.

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Combined Statements of Net Position - Periods Ended September 30, 2025 and December 31, 2024

	September 30, 2025	December 31, 2024
	(Unaudited)(Dollars in Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents[1]	$202,553	$193,097
Unrestricted investments	333,372	213,276
Restricted cash and cash equivalents	68,365	94,397
Restricted investments	776,249	282,515
Receivables, net of allowance for doubtful accounts	241,105	205,419
Other current assets	514,104	478,402
Total current assets	$2,135,748	$1,467,106
Noncurrent assets		
Restricted cash and cash equivalents	$496	$923
Restricted investments	141,839	132,115
Utility plant	10,833,374	10,472,167
Accumulated depreciation	(5,127,620)	(5,061,632)
Investment in associated companies	36,713	32,886
Costs to be recovered from future revenue	216,778	213,759
Regulatory assets – OPEB	144,886	144,886
Regulatory assets – Nuclear[2]	3,453,203	3,529,138
Regulatory assets – Cook Deferred Expenses[3]	498,937	517,075
Other noncurrent and regulatory assets	123,530	121,425
Total noncurrent assets	$10,322,136	$10,102,742
Total assets	$12,457,884	$11,569,848
DEFERRED OUTFLOWS OF RESOURCES		
Deferred outflows – pension	$27,578	$27,578
Deferred outflows – OPEB	57,682	57,682
Deferred outflows – Asset retirement obligation	455,827	502,785
Accumulated decrease in fair value of hedging derivatives	3,184	2,659
Unamortized loss on refunded and defeased debt	149,972	166,970
Total deferred outflows of resources	$694,243	$757,674
Total assets and deferred outflows of resources	$13,152,127	$12,327,522
LIABILITIES		
Long-term debt-net	$8,605,782	$7,961,634
Current liabilities	732,373	650,884
Noncurrent and other liabilities	1,069,360	1,081,511
Total liabilities	$10,407,515	$9,694,029
DEFERRED INFLOWS OF RESOURCES		
Deferred inflows – pension	$26,417	$26,417
Deferred inflows – OPEB	41,487	41,487
Accumulated increase in fair value of hedging derivatives	24,841	38,622
Nuclear decommissioning costs	235,100	220,145
Deferred inflows - Toshiba settlement	217,405	224,202
Total deferred inflows of resources	$545,250	$550,873
NET POSITION		
Net invested in capital assets	$1,938,484	$1,919,010
Restricted for debt service	106,039	15,766
Unrestricted	154,839	147,844
Total net position	$2,199,362	$2,082,620
Total liabilities, deferred inflows of resources & net position	$13,152,127	$12,327,522

(1) Includes certain hedging collateral of $9.9 million at December 31, 2024 and $0 at September 30, 2025.
(2) See "NUCLEAR UNITS – Regulatory Accounting."
(3) See "— Cook Exceptions Regulatory Asset and Cook Deferred Expenses" below.

Cook Rate Freeze Exceptions

The Authority is required to report on its compliance with the terms of the Cook Settlement Agreement and to identify the type and amount of any Cook Rate Freeze Exceptions that occurred during the Rate Freeze Period in annual reports (the "Annual Cook Compliance Reports") provided to the Court and to Central by April 30 of each year from 2021 through 2030. The next Annual Cook Compliance Report is due April 30, 2026. Copies of the Annual Cook Compliance Reports are available on the Authority's website at: https://www.santeecooper.com/about/settlement-reports/. *No statement or information on the Authority's website is incorporated by reference herein.*

The following table sets forth a description of the categories and amount of the Cook Rate Freeze Exceptions described in the reports filed through April 30, 2025, as well as estimated amounts for previous exceptions and a reconciliation to the Cook Exceptions Regulatory Asset as of December 31, 2025.

Cook Rate Freeze Exceptions
($ millions)

Reporting Period	Date Filed	Category of Qualifying Cost	Exceptions Reported in Previously Filed Annual Cook Compliance Reports	Total
8/1/2020 – 12/31/2020	4/30/2021	Change in Law	$ 5.2	
("2020 Cook Rate Freeze Exceptions")		Named Storm Event	1.2	
		Central Load Deviations	13.3	
1/1/2021 – 12/31/2021	4/29/2022	Changes in Law	$ 11.9	
("2021 Cook Rate Freeze Exceptions")		Named Storm Event	0.2	
		Fires[(1)]	36.8	
		Central Load Deviations	15.4	
1/1/2022 – 12/31/2022	4/28/2023	Changes in Law	$ 85.3	
("2022 Cook Rate Freeze Exceptions")		Fires	297.4	
		Named Storms	20.6	
		Interest[(2)]	2.7	
1/1/2023 – 12/31/2023	4/30/2024	Changes in Law	$ 63.6	
("2023 Cook Rate Freeze Exceptions")		Fires	141.3	
		Named Storm	1.0	
		Act of God and Flood	0.3	
		Interest[(2)]	20.7	
1/1/2024 – 12/31/2024	4/30/2025	Change in Law	$180.5	
("2024 Cook Rate Freeze Exceptions")		Fires	28.1	
		Interest[(2)]	25.9	
Total			$951.4	$951.4
			Less: Capital Exceptions[(3)]	(240.1)
			Less: Writedown	(153.7)
			Less: Other Adjustments	(7.6)
			Regulatory Asset (12/31/2024)	550.0
			Interim Interest January 2025-June 2025	12.5
			Less: 2025 Amortization	(17.5)
			Remaining Regulatory Asset (12/31/2025)	545.0

(1) This cost originally was reported in the 2021 Annual Cook Compliance Report as $43.4 million but was adjusted and disclosed in a subsequent report to account for changes in costs related to the events at Foresight's Sugar Camp Mine and Summer Nuclear Unit 1 (as defined herein).
(2) Costs directly associated with the debt incurred for the Cook Exceptions Regulatory Asset.
(3) Net of deferred interest on the Change of Law Effluent Limit Guidelines Exception (the "ELG Exception"). The Exceptions Agreement provides that the Authority may collect debt service on the ELG Exception consistent with the Authority's cost of service calculations used for retail ratemaking and Central's cost of service, as provided in the Central Agreement.

The Cook Rate Freeze Exceptions identified by the Authority in the respective Annual Cook Compliance Reports and described above, including additional expenses directly resulting from the costs of debt incurred relating to the Cook Exceptions Regulatory Asset, total $951.4 million.

Cook Exceptions Regulatory Asset and Cook Deferred Expenses

The Board authorized the use of regulatory accounting related to the Cook Rate Freeze Exceptions (and any subsequent adjustments pertaining to the exceptions), allowing the Authority to create the Cook Exceptions Regulatory Asset and to defer recognition on its Statement of Revenues, Expenses and Changes in Net Position of the expenses associated with the Cook Deferred Expenses.

In accordance with Governmental Accounting Standards Board ("GASB") Statement No. 62, creating this regulatory asset allows the Authority to recognize the Cook Deferred Expenses over the period the Authority expects to recover them through future rates after the Rate Freeze Period has ended, thus matching expenses and revenues. While the use of regulatory accounting deferred the recognition on the Authority's Statements of Revenues, Expenses and Changes in Net Position of these expenses during the Rate Freeze Period, it did not defer the Authority's obligation to pay these expenses during the Rate Freeze Period. The Authority has been funding a portion of these expenses on an interim basis from the proceeds of the issuance of its Commercial Paper Notes and draws on the Revolving Credit Agreements.

Through December 31, 2024, the Authority recorded a total of $703.8 million of Cook Deferred Expenses in the Cook Exceptions Regulatory Asset. This amount included (i) $71.3 million of the 2020 Cook Rate Freeze Exceptions and 2021 Cook Rate Freeze Exceptions, (ii) $398.1 million of the 2022 Cook Rate Freeze Exceptions, (iii) $166.5 million of the 2023 Cook Rate Freeze Exceptions, and (iv) $67.8 million of the Cook Rate Freeze Exceptions related to the adjustment of previously approved exceptions for the period beginning January 1, 2024 through December 31, 2024. The total amount of $703.8 million did not include approximately $240.1 million of capital costs, net of deferred interest, and is net of amounts reimbursed from insurance and other third parties.

The Resolution Amount of $550 million in the Exceptions Agreement will result in the Authority collecting 78% of the $703.8 million Cook Exceptions Regulatory Asset recorded as of December 31, 2024. The Authority wrote down the Cook Exceptions Regulatory Asset to $550 million in the fiscal year ending December 31, 2024, which increased expenses by $154 million and reduced reinvested earnings by this same amount for such fiscal year.

The Authority recorded $12.5 million in exceptions from January 1, 2025 through June 30, 2025, for interim interest incurred on debt incurred to finance the Resolution Amount. This adjustment resulted in an increase of the total Cook Exceptions Regulatory Asset to $562.5 million. In July 2025, the Authority began the amortization of the Cook Exceptions Regulatory Asset over a 10-year period to align with the timeline for collecting the Recovery Amount through the Cook Charge. See "RATES AND RATE COMPARISON – Cook Charge."

The Authority intends to finance the Recovery Amount using long-term bonds. The Authority has communicated with the Internal Revenue Service concerning the portions of the expenditures comprising the Cook Exceptions Regulatory Asset that can be financed on a tax-exempt basis as long term extraordinary working capital expenditures. The portions that cannot be financed using long term tax-exempt bonds will be financed using long term taxable bonds. These long-term bonds will be amortized over the remainder of the 10-year period ending on June 30, 2035, as provided for in the Exceptions Agreement.

Economic and Demographic Information

See APPENDIX D – "CERTAIN ECONOMIC AND DEMOGRAPHIC INFORMATION" for a description of certain financial, demographic, and economic information affecting the Authority's operations.

CUSTOMER BASE

Service Area

The Authority's primary business operation is the production, transmission, and distribution of electrical energy, both wholesale and retail, to citizens of the State. The Authority is one of the nation's largest municipal wholesale utilities, whose system serves directly or indirectly approximately two million South Carolinians in all 46 counties of the State. The Authority serves directly and indirectly suburban areas outside Charleston, Columbia, Greenville, and Spartanburg as well as the coastal areas of Myrtle Beach to Georgetown, Hilton Head Island, Kiawah Island, and Seabrook Island. In 2024, the Authority's kWh energy sales were comprised of 62.8% to wholesale customers, 22.1% to large industrial customers, and 15.1% to residential, commercial, and other customers. See "HISTORICAL SALES – Historical Demand, Sales, and Revenues."

Under State law, the Authority has an exclusive right to serve within its assigned retail service territory, and it has the exclusive right to continue to serve the large industrial premises outside its assigned service territory that it is currently serving. If any customers, premises, or electric cooperatives located outside the present service area of the Authority and being served by the Authority, including any subsequent expansions or additions by such customers, premises, or cooperatives, cease or discontinue accepting electrical service from the Authority, the Authority may subsequently sell and furnish electrical service to new customers, premises, or electric cooperatives from its major transmission lines in an amount not exceeding the amount of power the sale of which was lost by reason of such discontinuation of service.

Under State law, the Authority also has the right to enter into agreements with other electric suppliers concerning service areas and corridor rights. The SCPSC must approve said agreements and reassign said service area or corridor rights if, after giving notice and an opportunity for a hearing to interested parties, the SCPSC finds the agreements to be fair and reasonable. The SCPSC does not have the authority to alter or amend any such agreement unless all affected electric suppliers agree to the alteration or amendment.

See "Wholesale Customers – Central," "Wholesale Customers – Other," "Direct Customers – Large Industrial and Military," and "Retail Customers" below.

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Wholesale Customers - Central

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 19 distribution cooperatives listed below (the "Central Cooperatives") which are members of Central pursuant to long-term all-requirements power supply agreements, including the five electric distribution cooperatives that were formerly members of Saluda River Electric Cooperative, Inc. ("Saluda"). Central serves primarily residential, commercial, and small industrial customers in all 46 counties of the State. The Central Cooperatives serve areas ranging from sparsely populated rural areas to heavily populated suburban areas. The table below lists each of the Central Cooperatives, the location of their headquarters, and the number of customers for calendar years 2022-2024.

Central Cooperatives	Headquarters	2022 Customers	2023 Customers	2024 Customers
Aiken Electric Cooperative, Inc.	Aiken	51,376	52,365	53,479
Berkeley Electric Cooperative, Inc.	Moncks Corner	121,279	126,488	133,248
Black River Electric Cooperative, Inc.	Sumter	34,279	34,687	34,932
Blue Ridge Electric Cooperative, Inc.(1)	Pickens	70,780	72,208	73,374
Broad River Electric Cooperative, Inc.(1)	Gaffney	23,924	24,410	24,938
Coastal Electric Cooperative, Inc.	Walterboro	11,927	11,967	12,233
Edisto Electric Cooperative, Inc.	Bamberg	20,946	21,138	21,317
Fairfield Electric Cooperative, Inc.	Winnsboro	32,630	33,531	34,232
Horry Electric Cooperative, Inc.	Conway	91,101	94,458	99,014
Laurens Electric Cooperative, Inc.(1)	Laurens	62,138	63,593	64,665
Little River Electric Cooperative, Inc.(1)	Abbeville	14,991	15,262	15,372
Lynches River Electric Cooperative, Inc.	Pageland	22,001	22,246	22,422
Marlboro Electric Cooperative (2)	Bennettsville	6,651	6,702	N/A
Mid-Carolina Electric Cooperative, Inc.	Lexington	59,578	59,985	60,877
MPD Electric Cooperative, Inc. (2)	Florence	N/A	N/A	39,062
Newberry Electric Cooperative, Inc.	Newberry	13,528	13,659	13,810
Palmetto Electric Cooperative, Inc.	Ridgeland	77,875	79,231	80,875
Pee Dee Electric Cooperative, Inc. (2)	Darlington	31,179	32,249	N/A
Santee Electric Cooperative, Inc.	Kingstree	44,445	44,729	45,021
Tri-County Electric Cooperative, Inc.	St. Matthews	18,355	18,411	18,466
York Electric Cooperative, Inc.(1)	York	68,017	69,289	70,330
Total Customers		877,000	896,608	917,667

(1) Former members of Saluda.
(2) In 2024, Marlboro Electric Cooperative, Inc. and Pee Dee Electric Cooperative, Inc. merged as MPD Electric Cooperative.

The Authority supplies the total power and energy requirements of the Central Cooperatives less amounts which Central purchases directly from Southeastern Power Administration (the "SEPA"), amounts provided by Duke Energy Carolinas, LLC ("Duke Energy Carolinas"), a subsidiary of Duke Energy Corporation, as described below, and small amounts purchased from others.

In 2024, revenues pursuant to the Central Agreement amounted to approximately 59% of the Authority's revenues from sales. See "INVESTMENT CONSIDERATIONS – The Electric Utility Industry Generally."

The Authority serves Central under the terms of a coordination agreement between the Authority and Central which became effective in January 1981 (as subsequently amended or revised, the "Central Agreement") and cannot be terminated earlier than December 31, 2058. Under the Central Agreement's 10-year rolling notice provision, for a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. Central has entered into all-requirements agreements with the Central Cooperatives that extend through December 31, 2058, and such agreements obligate those members to pay their share of Central's costs, including costs paid under the Central Agreement. Central's board developed an exit methodology which is available to all members. If a member wishes to exit, they must submit a proposal to Central's board which will be evaluated to determine possible acceptance of contract termination. At this time, the Authority is not aware of any proposals that have been submitted to Central's board.

Rates under the Central Agreement are developed under a cost of service methodology and are adjusted automatically on a monthly basis to reflect actual fuel cost and on an annual basis to reflect actual non-fuel cost, including operation and maintenance, debt service, and a Capital Improvement Fund Requirement. The cost of service methodology includes, among other things, allocating debt service and Capital Improvement Fund Requirements to the functional cost categories, such as production, transmission, or distribution based on net plant balances. Central's rates were also frozen as part of the Rate Freeze, and such rates were unfrozen as of January 1, 2025. See "RATES AND RATE COMPARISON – End of Rate Freeze Period and 2025 Rate Adjustments."

The Central Agreement was revised in May of 2013 (the "2013 Amendment") to, among other things, formalize the resource planning process, including outlining how the parties will jointly plan and determine the need for new resources. In accordance with the 2013 Amendment, Central is able to decide whether or not to participate in major new resources which were not completed or under construction as of January 1, 2013. If Central decides to participate in a resource, the costs for the new resource are included and shared under the Central Agreement. If Central decides not to participate in a proposed resource, the parties will obtain their own resources based on their *pro rata* share of the proposed resource, and each party will be responsible for the cost of its own non-shared resources. The 2013 Amendment was intended to provide certainty to the Authority's planning process and, with the earliest termination date deferred to December 2058, allow the Authority to align its existing and future debt service with the useful lives of its assets and its future revenue streams. See "POWER SUPPLY AND PLANNING – Central Option Relating to Proposed Natural Gas Combined Cycle Shared Resource."

In accordance with and as permitted under the terms of the Central Agreement, Central audits the Authority's books and the annual cost of service study used to develop their rates under the Central Agreement.

Wholesale Customers - Other

Sales to Wholesale - Other customers, including off-system sales to other utilities and power marketers, represented approximately 2.2% of revenues from sales in 2024.

Wholesale Customers On-System. The Authority provides wholesale electric service to two on-system wholesale customers, the City of Georgetown and the City of Bamberg. Service agreements were executed in 2013 with the City of Georgetown and the City of Bamberg with initial terms of 10 years and 20 years, respectively. In 2023, the Authority and City of Georgetown amended the City's contract which included extending the initial term of the City's contract from 10 years to 17 years.

Wholesale Customers Off-System. The Authority provides wholesale electric service to four off-system customers (*i.e.*, outside of the Authority's transmission and distribution system) pursuant to long-term contracts:

City of Seneca. The Authority executed a service agreement to provide wholesale electric service to the City of Seneca beginning July 1, 2015, for an initial term of 10 years. Under the terms of its contract with the Authority, service to the City of Seneca will continue under the service agreement unless and until such agreement is terminated by the City of Seneca with two years advance written notice. No notice has been received to date. Power generated by the Authority is being delivered to the City of Seneca through the Authority and Blue Ridge Electric Cooperative, which has joined the contract as an additional electric provider to the City of Seneca.

Town of Waynesville, North Carolina. The Authority entered into a long-term purchase agreement with the Town of Waynesville to provide wholesale electric service beginning January 1, 2017, for a term of 10 years. The current agreement will end at the end of 2026, and the Authority has no plans to renew or extend it.

Piedmont Municipal Power Agency ("PMPA"). The Authority has a long-term power agreement with PMPA pursuant to which the Authority provides PMPA its supplemental electric power and energy requirements (ranging from approximately 200 MW to 300 MW) above its current resources. This agreement commenced on January 1, 2014, for a term of no less than 12 years. PMPA has notified the

Authority that three member cities provided notice to terminate their supplemental agreements with PMPA effective December 31, 2028, and these three participants will no longer purchase supplemental power through the current agreement effective as of such date. PMPA has also notified the Authority that the other seven member cities provided notice to terminate their supplemental agreements with PMPA effective December 31, 2029, and that these seven participants will no longer purchase supplemental power through the current agreement effective as of such date. The Authority and PMPA are currently negotiating a new service agreement, which is projected to reduce the amount of PMPA supplemental electric power and energy requirements as compared to the current agreement.

Dominion Energy South Carolina, Inc. ("Dominion"). Dominion gave notice to terminate service to the former Charleston Navy Yard effective May 6, 2020, but remains a customer of the Authority under an unrelated agreement.

All of the Authority's other wholesale customer contracts contain provisions that would allow for early termination of the contract for a variety of reasons. None of such termination provisions have been triggered to date.

Direct Customers - Large Industrial and Military

The Authority's direct customers currently include 27 large industrial and military customers, including Joint Base Charleston. The Authority offers a large power rate schedule for large industrial customers which contract for a minimum of 1,000 kilowatts ("kW") for initial periods of not less than five years (Large Light and Power Rate ("Schedule L")). As of December 2024, the Authority had 704 MW of non-firm power under contract through Schedule L. The provisions of Schedule L contain demand and energy recovery components and include monthly automatic fuel adjustment and demand sales adjustment clauses, minimum demand charges, and other provisions generally used in large industrial power rate schedules. Customers served under Schedule L, including customers served under the "Interruptible" and "Economy Power – Optional" riders of Schedule L, were subject to the Rate Freeze, locking the fuel adjustment, demand sales adjustment, and economic development sales adjustment values to those of Schedule B of the Cook Settlement Agreement for the entire Rate Freeze Period. See "RATES AND RATE COMPARISON – End of Rate Freeze Period and 2025 Rate Adjustments." Of the 29 customers served under Schedule L, 27 customers are directly served by the Authority including Joint Base Charleston, and two customers are served indirectly through Central. The Authority also serves the Regional Water Systems under Schedule L; however, these revenues are classified as an intra-departmental sale and are not included in the industrial sales revenue information provided in the paragraph below. During 2024, revenues from sales to large industrial customers averaged 5.08 cents per kWh.

The average cost per kWh varies depending upon the customer's usage and load factor. Sales to large industrial customers during 2024 were approximately $305 million and represented approximately 16.2% of revenues from sales. This includes 6.3% for Century Aluminum of South Carolina, Inc., formerly Alumax of South Carolina, Inc. ("Century Aluminum"), 4.9% for Nucor Corporation ("Nucor"), and 3.5% for the next eight largest industrial customers, in each case as a percentage of total revenues from sales, of which no one customer represents more than 0.9% of total revenues from sales. Of the 16.2% of revenues from sales, approximately 50.3% represents fuel cost recovery.

Planning for Load Growth from Data Centers. As part of its planning process, the Authority performs an annual load forecast of the demand and energy needs of its customers, including the needs of Central's member cooperatives served through the Authority's balancing area. The Authority's current load forecast used to develop its 2025 Integrated Resource Plan indicates a compound annual growth rate of 1.7 percent of the winter demand peak. This growth is driven by continued customer growth in the Authority's direct-served residential class as well as growth in the needs of Central member cooperatives, including several new large loads that have located within Central member cooperative territory.

Additionally, the Authority's load forecast includes an upward adjustment to demand and energy requirements to plan for prospective new large loads that have approached the Authority or a Central member cooperative to discuss potentially receiving service. This adjustment uses a probabilistic analysis of the likelihood of the prospective new load requiring service based on a variety of factors. In the 2025 Integrated Resource Plan, the Authority evaluated approximately 3,900 megawatts ("MW") of potential new loads for inclusion in the forecast and ultimately made an upward adjustment of 865 MW to the 2037 winter peak. The development of this probabilistic analysis process follows an SCPSC order for the Authority to engage stakeholders regarding the best approach to incorporate such prospective new loads into the load forecast.

A significant portion of the new large loads and the prospective new loads evaluated for inclusion in the Authority's load projections are related to requests for service from data centers, and the Authority estimates that data centers represent approximately 70 percent of the total projected load growth.

The American Public Power Association ("APPA") has approached the United States Treasury Department concerning private business use ("PBU") regulations with the primary goal being to ensure that public power utilities can meet the massive electricity demand from sectors like AI and data centers without losing the tax-exempt status of their bonds. The Authority monitors the impact of PBU on its tax-exempt bonds. PBU relates to federal tax law restrictions that limit how much of a tax-exempt bond-financed facility can be used by private entities. These rules are significant for public power utilities because exceeding these limits can cause tax-exempt bonds to lose their tax-exempt status, making them taxable "private activity bonds." If the limits established by the PBU regulations are exceeded, the Authority would have to remediate portions of its tax-exempt bonds, which typically requires taxable bonds being issued to refinance the tax-exempt bonds subject to remediation. There can be no assurance that APPA will be successful in obtaining relief for public power utilities.

Power Contract with Century Aluminum. The Authority is party to an agreement with Century Aluminum effective September 1, 2025, with a term ending December 31, 2031. Century Aluminum has been a customer of the Authority since 1977. Century Aluminum's plant is currently operating at 75% capacity at the current contract demand of approximately 300 MW. The current agreement includes an increase of 100 MW of additional load under the L-rate, which would bring the plant to 100% capacity. Approximately 50% of their total load is served under Schedule L, and the other 50% is served under other currently available non-firm riders. In addition to its standard termination provisions, the contract contains a provision that allows for early termination by Century Aluminum upon 120 days' prior written notice, effective no earlier than December 31, 2028.

Long-Term Power Contract with Nucor. Nucor has been a customer since 1996 and receives service from the Authority under Schedule L. Nucor through its wholly owned subsidiary UIG, LLC, constructed a new air separation unit for the purpose of supplying industrial gases for the mill's steel making operations which came online January 1, 2025. Nucor and the Authority are parties to a service agreement effective August 1, 2024, with an initial term ending July 31, 2030. This agreement will accommodate the addition of Nucor's new air separation unit and galvanized line production. Termination of service requires reduction in contract demands to zero, as determined per the notice requirements and reduction amounts specified under the applicable rate schedules; provided that the agreement cannot be terminated and contract demand reductions cannot be effective prior to July 31, 2030. To date Nucor has not provided notice to terminate. In total, this contract provides for delivery of approximately 350 MW of power, the majority of which is provided under the Authority's non-firm rate schedules.

Retail Customers

The Authority also serves directly approximately 216,000 residential, commercial, and small industrial retail customers in its assigned retail service territory, which includes parts of Berkeley, Georgetown, and Horry counties.

The Authority owns and operates distribution facilities and serves retail customers in two non-contiguous areas covering portions of Berkeley, Georgetown, and Horry Counties. These service areas include 3,069 miles of distribution lines. The following table presents retail customer growth from 2020 through 2024 in these areas.

Retail Customer Counts (2020 to 2024)

Year	Residential	Commercial and Small Industrial	Total	Annual Increase %
2020	162,971	30,724	193,695	2.6%
2021	167,881	30,813	198,694	2.5
2022	172,407	32,359	204,766	3.1
2023	182,208	30,389	212,597	3.8
2024	185,529	30,938	216,467	1.8

Sales to residential, commercial, and small industrial customers and certain other customers are made pursuant to rate schedules established from time to time by the Authority. The vast majority of such rate schedules include monthly automatic fuel adjustment and demand sales adjustment clauses. However, the monthly automatic fuel adjustment and the demand sales adjustment, as well as the economic development sales adjustment, were locked for select rates of these customer classes during the Rate Freeze Period under the Cook Settlement Agreement. Additionally, the rate schedules for most of these customers were not able to be changed during the Rate Freeze Period, effectively locking in the current rate schedules and pricing for the duration of the Rate Freeze Period, which ended in January 2025. Sales to this customer group represented approximately 22.7% of revenues from sales in 2024. See "Rate Comparison" and "Rate Structure" under "RATES AND RATE COMPARISON."

RATES AND RATE COMPARISON

Authorization

Under the Act, the Board is empowered and required to set rates as necessary to produce revenues sufficient to provide for the payment of all expenses, the conservation, operation and maintenance of its facilities and properties, and the payment of its interest and principal on its bonds, notes, and other obligations. The Board is required to adopt and publish pricing principles that respect and balance certain factors including, but not limited to, adherence to the Authority's mission to be a low-cost provider, reliability, transparency, preservation of the Authority's financial integrity, equity among customer classes, gradualism in adjustments to its pricing and rate schedule type, encouragement of efficiency and demand response, adequate notice to customers, and relief mechanisms for financially distressed customers. The Act establishes a process that is similar to the process previously approved by the Board for prior rate studies and adjustments.

While no governmental or regulatory entity, other than the Board, has jurisdiction over the rates of the Authority, in accordance with the terms of the Cook Settlement Agreement, the Board in 2020 authorized management to lock the rate schedules and variable rate components of select rates consistent with the rates that were developed and projected in the 2019 Reform Plan during the Rate Freeze Period. This period ended for all customers on January 15, 2025. See " – End of Rate Freeze Period and 2025 Rate Adjustments" below.

Information regarding the Authority's rates may be viewed at the following address: https://www.santeecooper.com/rates/. *No statement or information on the Authority's website is incorporated by reference herein*.

Revenue Obligation Resolution Requirements

The Revenue Obligation Resolution requires the Authority to establish, maintain, and collect rents, tolls, rates, and other charges for power and energy which will be adequate to provide the Authority with Revenues sufficient to pay when due all payments which the Authority is obligated to pay from the Revenues of the System by law or contract. The Revenue Obligation Resolution also requires that, so long as any Revenue Obligations are Outstanding, the Authority may not furnish or supply electric, or other form of energy or water furnished by the Authority, or in connection with the operation of the System, free of charge to any person, firm, or corporation. See "SECURITY FOR THE 2026 BONDS – Rate Covenant."

End of Rate Freeze Period and 2025 Rate Adjustments

The class action lawsuit relating to the Authority's decision in 2017 to suspend construction of the Nuclear Units was settled in 2020 pursuant to the Cook Settlement Agreement. The Board agreed in the Cook Settlement Agreement to the Rate Freeze at the rates projected in the Authority's plan dated January 3, 2020, submitted to the South Carolina General Assembly pursuant to Act No. 95 of 2019 (the "2019 Reform Plan") for the Rate Freeze Period.

The 2019 Reform Plan included a financial forecast and projected most Central rates as well as three major adjustments to the primary rate components (energy and demand charges) of most customers of the Authority; the Fuel Adjustment, Demand Sales Adjustment, and Economic Development Sales Adjustment. The purpose of these adjustments is to true-up values from base rates set during the last rate study to actual. Under normal conditions most Central rates (except for fuel) are projected annually in the corporate budget and trued-up at year end; fuel rates for Central are calculated and applied monthly. Additionally, in normal conditions retail rate adjustment values are calculated monthly using actual data. As part of the Cook Settlement Agreement, however, these values were no longer based on annual budget values adjusted to actual or monthly calculations; during the Rate Freeze, they largely were frozen to the values provided in the 2019 Reform Plan financial forecast (the "Settlement Rates").

The implementation of Settlement Rates also froze the majority of the Authority's rate schedules for non-Central customers. This resulted in rates being frozen for almost all residential and commercial customers participating in the Settlement Rates, as well as industrial customers and the Interruptible and Economy Power Optional riders. Settlement Rates provided in the Cook Settlement Agreement for industrial customers also applied to the fuel adjustment of municipal customers with contractual rates based on the municipal light and power rate.

In accordance with the terms of the Cook Settlement Agreement, the Rate Freeze Period started in 2020 and ended for all bills rendered after January 15, 2025. Accordingly, the Authority has reinstated the fuel adjustment, demand sales adjustment, and economic development sales adjustment for the Authority's retail customers with rate codes designated in the appendices of the Cook Settlement Agreement and rates to Central under the Central Agreement. Approximately 75% of the Authority's costs are recovered annually from these automatic rate adjustments.

In June 2023 management requested permission from the Board to undertake a comprehensive rate study for the purpose of revising residential, commercial, industrial, and lighting class rates. At that time, the Authority had not increased its electric rates since April 2017. The primary motivation behind the proposed revisions was a projected revenue deficit of approximately $40 million from the above-mentioned customer classes starting in 2025. The Board received the results of the comprehensive rate study (the "2024 Rate Study"), which recommended a system average 4.9% base rate increase effective in April of 2025.

As required by the Act, management provided notice of the proposed rates to customers and various stakeholders at least 180 days before the Board's vote on the proposed adjustments. Based on stakeholder feedback received during the public comment period, management provided modified rate schedules. The modifications were primarily revenue neutral and included reductions to the proposed demand charge for residential and small commercial customers. The modified proposal included an 8.8% increase for residential customers, a proposed 4.1% increase for commercial customers, a proposed 5.0% increase for lighting customers, and a proposed 2.6% increase for industrial customers. On December 9, 2024, the Board voted to approve the modified rates presented, concluding the 2024 Rate Study. Under the Act, rates cannot go into effect sooner than 60 days after Board approval, and the new rates were implemented for customer billing beginning on April 1, 2025.

The Authority monitors projected revenues and revenue requirements and adjusts rates when a revenue deficiency is projected to occur. The Authority's recent financial plan indicates a revenue deficiency beginning in 2027, thus requiring a retail rate adjustment. Any changes in retail rates are subject to a formal public notice and comment period prior to Board approval for implementation.

Wholesale Rates - Central

Rates under the Central Agreement have historically been determined in accordance with the cost of service methodology contained in the Central Agreement. Under the Central Agreement, Central initially pays for its power supply based on Central's projected loads and the Authority's projected costs. The charges are then adjusted automatically on a monthly basis to reflect actual fuel costs and on an annual basis to reflect actual non-fuel costs, and Central is charged or credited the difference between the amounts paid based on projected rates and the amounts due based on actual rates. During 2024, revenues from sales to Central and other wholesale requirements customers averaged 6.69 cents per kWh. For a more detailed discussion of the terms of the agreement with Central see "CUSTOMER BASE – Wholesale Customers – *Central*."

In August of 2020, the majority of Central's rates were fixed to values dictated in the terms of the Cook Settlement Agreement, as described above under " – End of Rate Freeze Period and 2025 Rate Adjustments." In January of 2025, Central's rates returned to being calculated as described above under "CUSTOMER BASE – Wholesale Customers – Central."

Wholesale Rates - Other

The Authority's rates with respect to its wholesale customers other than Central are driven by the specific requirements of its agreements with each of the wholesale customers. The Authority has entered into service agreements, purchase agreements, and power agreements with its wholesale customers, other than Central. See "CUSTOMER BASE – Wholesale Customers – Other" above.

Direct Customer Rates - Large Industrial and Military

The Authority offers a large power rate schedule for large industrial and military customers which contract for a minimum of 1,000 kW for initial periods of not less than five years. See "CUSTOMER BASE – Direct Customers – Large Industrial and Military" above.

Retail Rates

With the introduction of new rates on April 1, 2025, the Authority now has three-part rates including a demand charge for the majority of its residential, commercial, and industrial customers. Demand charges assign fixed cost recovery to the users that most directly cause those costs to be incurred. Prior to the implementation of new rates, the Authority had seasonal rates for the majority of its customers. Seasonal energy charges reflect higher charges during the summer months when higher energy costs are incurred. During 2024, revenues from sales to residential, commercial, and other customers averaged 10.44 cents per kWh based on the then current rates which reflected the lock of fuel adjustments and credits for demand sales adjustments described below.

The Authority's rate schedules include monthly automatic fuel adjustment clauses which provide for increases or decreases to the basic rate schedules to cover increases or decreases in the cost of fuel to the extent such costs vary from a predetermined base cost, based on a three-month rolling average. The Authority's rate schedules also include a demand sales adjustment clause which provides for increases or decreases to the base rate schedules to reflect increases or decreases in demand revenues from non-firm sales (such as interruptible and economy power rate schedules and riders) and off-system sales to the extent such revenues vary from predetermined amounts included as credits to firm base rates. These adjustment clauses were locked for customers with rate codes designated in the Cook Settlement Agreement during the Rate Freeze Period, which impacted the majority of residential, commercial, and industrial customers. See " – End of Rate Freeze Period and 2025 Rate Adjustments" above. Additionally, the Authority's rate schedules include a deferred cost recovery adjustment clause to collect deferred costs associated with Cook Rate Freeze Exceptions.

The Authority has developed and offers demand rates, time-of-use, and off-peak rates to its direct-served commercial and industrial customers to encourage them to reduce their peak demand.

The Authority introduced new rates for retail and municipal customers on April 1, 2025. See "2024 Rate Study and 2025 Rate Adjustments" below. This change represented the first change to base rates since April 1, 2017.

In April 2025, the Board approved the adoption of an Experimental Industrial Large Load Service Rate L-25-LL to apply to large loads 50 MW or greater or mobile large loads 1 MW or greater. The rate contains provisions such as longer initial contract terms, greater minimum billed demands, cash and credit collateral requirements, and additional incremental demand charges intended to protect retail customers from stranded costs associated with serving large loads. This rate expires April 24, 2029.

Retail Rate Process

The Act establishes a process for the Board to follow when creating or revising any approved retail rate schedules which includes, among other things, notice to customers, as well as to the ORS, of the date the Board is expected to vote on a proposed rate adjustment, and the opportunity for a party in interest to provide written or oral comments or questions. Notwithstanding the process established by the Act, the Authority may place adjusted rates and charges into effect on an interim basis under emergency circumstances, such as the avoidance of default of its obligations and to ensure proper maintenance of the System, provided that such interim rates may not remain in effect for more than eighteen months.

The Act also establishes the procedure by which a party, including the ORS, can challenge any rate adjustments that have been approved by the Board with the exclusive remedy being a prospective adjustment of a new rate. On appeal, the South Carolina Supreme Court may not substitute its judgment for the judgment of the Board as to the weight of the evidence on questions of fact. The court may affirm the decision of the Board or remand the case back to the Board for further proceedings. The South Carolina Supreme Court may reverse or modify the decision if substantial rights of the appellant have been prejudiced because the Board's findings, inferences, conclusions, or decisions are: (a) in violation of constitutional or statutory provisions; (b) in excess of the statutory authority of the Authority; (c) made upon unlawful procedure; (d) affected by other error of law, (e) clearly erroneous in view of the reliable, probative, and substantial evidence on the whole record; or (f) arbitrary or capricious, or characterized by abuse of discretion, or clearly unwarranted exercise of discretion.

While the Act establishes a process for the Board of the Authority to follow with respect to rate setting and the Board must ensure that the statutory process established under the Act is followed, the Act also provides that this process shall in no way limit or derogate from the State's covenants in the Act not to impair, alter, limit, or restrict the Authority's power to establish rates and charges sufficient to provide for payment of its expenses and debt service on its obligations, including its Revenue Obligations and its statutory obligation to establish rates that are consistent with the best interests of the Authority.

Cook Charge

Certain disputes arising from the Cook Rate Freeze Exceptions and the Authority's compliance with specific portions of the Cook Settlement Agreement were resolved pursuant to the terms of a settlement agreement (the "Exceptions Agreement"). The Exceptions Agreement provides, among other things, that the Resolution Amount recoverable in rates by the Authority for certain Cook Rate Freeze Exceptions identified in the Annual Cook Compliance Reports described above in the table under "FINANCIAL INFORMATION – Cook Rate Freeze Exceptions" will be $550 million. The Authority is authorized to collect the Recovery Amount over a 10-year period.

The Authority will recover the Recovery Amount through imposition of the Cook Charge which shall consist of the debt service on the debt issued to finance the Recovery Amount plus amounts to reflect the Minimum Capital Improvement Requirement at 8%, payments to the State, and sums in lieu of taxes on such debt service. The Cook Charge will be calculated separately from the Authority's cost of service calculations used for the Authority's retail ratemaking and Central's cost of service pursuant to the Central Agreement. The Cook Charge will be allocated 65.4% to Central and 34.6% to the Authority's non-Central customers.

The Authority began collecting the Cook Charge from Central and non-Central customers in July 2025. The estimated impact on customer bills is an increase of approximately 3% beginning in 2025 and continuing over the 10-year period.

Retail Rate Comparison

Comparisons of the Authority's average cost per kWh for firm service at selected monthly usage levels with the average cost per kWh of the three investor-owned utilities that serve the State, based on rates on file with the SCPSC for the period of December 1, 2024 to November 30, 2025, are set forth below.

	Residential 1,000 kWh	Commercial 5,000 kWh	Industrial 9,000 kW-5,000,000 kWh
Authority	12.53¢	10.28¢	6.86¢
Duke Energy Carolinas	13.26¢	12.30¢	6.70¢
Duke Energy Progress	15.01¢	12.06¢	8.10¢
Dominion	15.28¢	13.52¢	8.35¢

HISTORICAL SALES

Historical Demand, Sales, and Revenues

The following table sets forth the peak demand and firm off-system sales to other utilities on the Authority's system, as well as the gigawatt hour ("GWh") sales, and electric revenues of the Authority for the years 2020 through 2024.

	Peak Demand		Sales		Revenue from Sales		
Year	MW	Annual % Increase (Decrease)	GWh	Annual % Increase (Decrease)	Amount (Dollars in Thousands)	Annual % Increase (Decrease)	Cents Per kWh
2020	4,467	(2.5)	22,233	(4.3)	1,602,923	(5.4)	7.21
2021	4,634	3.7	24,601	10.7	1,741,341	8.6	7.08
2022	5,342	15.3	26,224	6.6	1,924,377	10.5	7.34
2023	4,940	(7.5)	26,185	(0.2)	1,825,717	(5.1)	6.97
2024	5,325	7.8	27,151	3.7	1,881,615	3.1	6.93

The following table sets forth energy sales by customer class for the years 2020 through 2024.

Sales (GWh)

	2024		2023		2022		2021		2020	
Class of Customers		% of Total		% of Total		% of Total		% of Total		% of Total
Wholesale	17,053	62.8	16,251	62.1	16,294	62.1	15,402	62.6	14,564	65.5
Large Industrial	5,995	22.1	5,999	22.9	6,002	22.9	5,264	21.4	3,995	18.0
Residential, Commercial, Small Industrial and Other	4,103	15.1	3,935	15.0	3,928	15.0	3,935	16.0	3,674	16.5
Total	27,151	100.0	26,185	100.0	26,224	100.0	24,601	100.0	22,233	100.0

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The following table sets forth revenues from energy sales by customer class for the years 2020 through 2024.

Revenues (Dollars in Thousands)

Class of Customers	2024	% of Total	2023	% of Total	2022	% of Total	2021	% of Total	2020	% of Total
Wholesale	$1,149,346	61.1	$1,108,761	60.7	$1,131,578	58.8	$1,059,588	60.9	$1,022,397	63.8
Large Industrial	304,622	16.2	306,603	16.8	386,211	20.1	274,202	15.7	196,682	12.3
Residential, Commercial, Small Industrial and Other	427,647	22.7	410,154	22.5	406,588	21.1	407,551	23.4	383,844	23.9
Total	$1,881,615	100.0	$1,825,717	100.0	$1,924,377	100.0	$1,741,341	100.0	$1,602,923	100.0

POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES

Power Supply

The Authority plans for firm power supply from its own generating capacity and firm power contracts to equal its firm load, including a 20% winter reserve margin. The Authority owns generation facilities with a current total summer capacity rating of 5,163 MW and a total winter capacity rating of 5,388 MW. In addition, the Authority enters into various power purchase arrangements through which the Authority purchases additional capacity and energy. In 2025, such purchases represented 910 MW (or 14.4%) of the Authority's winter power supply peak capability. See "Power Purchase Agreements or Purchases" below for additional information.

The electric generation, transmission and distribution facilities owned by the Authority, as well as certain transmission facilities owned by Central, are operated and maintained by the Authority as a fully integrated electric system. The Authority has direct interconnections with five entities with which the Authority has long-term power contracts for energy interchange. See "Interconnection and Interchanges" below.

The table below details the Authority's resource capacity classified by fuel type for the winter power supply peak capability.

Source of Power Supply (Capacity)	(MW)	% of Total
Coal	3,480	55.2%
Natural Gas and Oil	1,413	22.4
Long-Term Contracted Purchases	910	14.4
Nuclear	322	5.1
Owned Hydro Generation	142	2.3
Landfill Methane Gas	26	0.4
Solar(1)	12	0.2
Total	6,305	100.0%

(1) Includes 5 MW of the Authority's owned resources and 483 MW of purchased power on a nameplate basis. The capacity shown in the table represents the effective load carrying capacity of solar.

The Authority is currently not subject to any renewable requirements or mandates; however, the Authority supports renewable energy development in its service area. Renewable energy programs include a distributed generation rider in which the Authority purchases excess power produced by a retail customer who installs a solar system on their home or business as well as a community solar program in which the Authority contracts with customers to provide them a portion of the output from an existing solar power purchase agreement. This program allows customers to participate in solar generation even if they choose not to install solar systems on their home or business.

Existing Generating Facilities

The Authority's generating facilities are set forth in the following table.

Generating Facilities	Location	Initial Date in Service	Winter Capacity (MW) (1)	Summer Capacity (MW) (1)	Energy Source
Jefferies Hydroelectric Generating Station	Moncks Corner	1942	140	140	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	20	16	Oil/Gas
Combustion Turbines Nos. 3 and 4(2)	Myrtle Beach	1972	20	19	Oil
Combustion Turbine No. 5	Myrtle Beach	1976	25	21	Oil
Combustion Turbine No. 1	Hilton Head Island	1973	20	16	Oil
Combustion Turbine No. 2	Hilton Head Island	1974	20	16	Oil
Combustion Turbine No. 3	Hilton Head Island	1979	60	52	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	280	275	Coal
No. 2		1977	290	285	Coal
No. 3		1980	290	285	Coal
No. 4		1981	290	285	Coal
Summer Nuclear Unit 1	Jenkinsville	1983	322 (3)	322 (3)	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	585	580	Coal
Unit 2		1983	570	565	Coal
Unit 3		2007	580	585	Coal
Unit 4		2008	595	605	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG (4)
Lee County Landfill Gas Station	Bishopville	2005	11	11	LMG
Richland County Landfill Gas Station	Elgin	2006	8	8	LMG
Georgetown County Landfill Gas Station	Georgetown	2010	1	1	LMG
Berkeley County Landfill Gas Station	Moncks Corner	2011	3	3	LMG
Rainey Generating Station	Starr				
Unit 1		2002	520	460	Gas
Unit 2A		2002	180	146	Gas
Unit 2B		2002	180	146	Gas
Unit 3		2004	90	75	Gas
Unit 4		2004	90	75	Gas
Unit 5		2004	90	75	Gas
Cherokee Generating Station	Gaffney	1998	98	86	Gas
Solar(5)	Various	2006-2019	5	5	Solar
Total Capability			5,388	5,163	

(1) Capacity represented by Net Dependable Capacity (NDC).
(2) Myrtle Beach Combustion Turbine No. 4 is currently unavailable until further notice and is not included in totals above.
(3) Represents the Authority's one-third ownership interest in Summer Nuclear Unit 1.
(4) Landfill Methane Gas ("LMG").
(5) Capacity values for solar reflected nameplate capacity. The Authority owns approximately 5 MW of solar capacity.

Fossil Fuel Generation

All Authority-operated units are maintained with computerized maintenance management systems and the use of preventive, predictive, and proactive maintenance practices to achieve high reliability and efficiency at low maintenance cost. In its maintenance program, the Authority utilizes technologies such as vibration analysis, oil analysis, thermography, laser alignment, and non-destructive testing. The Authority continues to implement equipment maintenance programs for the units including major unit components such as control systems, steam generators, and turbine generators. See "THE AUTHORITY – Capital Improvement Program and Future Financings."

Coal-Fired Generation Performance Indicators. Performance monitoring systems are in place at the Authority's coal-fired generating stations to optimize each unit's operation while complying with environmental requirements.

The following table sets forth certain performance indicators for the Authority's coal-fired generation for the years 2022 through 2024.

	2022	2023	2024
Capacity Factor - %	32.6	36.2	39.6
Availability Factor - %	85.9	82.3	81.8
Forced Outage Rate - %	3.4	3.2	8.8
Net Heat Rate (BTU/kWh)	10,169	10,290	10,524

Gas-Fired Combined Cycle Generation. As of November 1, 2023, the Authority acquired a 98 MW natural gas-fired, combined-cycle generation facility located in Gaffney, South Carolina (the "Facility"). The acquisition was accomplished by purchasing 100% of Cherokee County Cogeneration Partners, LLC, the entity that owns (i) the license to operate the Facility, (ii) all assets and equipment related to the Facility, and (iii) all necessary permits. The Facility is interconnected to the electric transmission system of Duke Energy Carolinas and is connected to the existing Transcontinental Gas Pipeline Company, LLC ("Transco") natural gas pipeline which runs through western South Carolina.

Central approved the acquisition as a proposed shared resource. The acquisition was additionally approved by the SCPSC, and the acquisition of the subject real property was approved by the JBRC. The transaction between the Authority and Cherokee Generating, LLC closed on October 31, 2023, and the Facility has been available since that date via block scheduling across the intervening transmission system and operated intermittently by the Authority based on system conditions. On August 1, 2024, a pseudo-tie was put in place, virtually bringing this unit into the Authority Balancing Area, thereby allowing the Authority to dynamically dispatch this unit and follow its load on a real-time basis.

The following table sets forth certain performance indicators for the Authority's combined cycle gas-fired generation for the years 2022 through 2024.

	2022	2023	2024
Net Capacity Factor - %	89.7	78.3	68.3
Availability Factor - %	94.7	85.3	74.4
Forced Outage Rate - %	0.1	0.9	.3
Combined Cycle Net Heat Rate (BTU/kWh)	7,135	7,129	7,361

Nuclear Generation

The Authority owns a one-third undivided ownership interest in the Virgil C. Summer Nuclear Generating Station Unit 1 ("Summer Nuclear Unit 1"), which has a pressurized water reactor with a Maximum Dependable Capacity ("MDC") of 966 MW net. The Authority's share of the MDC is 322 MW. Dominion owns the remaining two-thirds undivided ownership interest and operates and maintains Summer Nuclear Unit 1 on its own behalf and as the Authority's agent.

The NRC oversees plant performance through the Reactor Oversight Process ("ROP") assessment program. The ROP assessment program collects information from inspections and performance indicators ("PIs") which the NRC uses to objectively assess a facility's safety performance. The ROP consists of three key strategic performance areas: reactor safety, radiation safety, and safeguards. Summer Nuclear Unit 1 is currently in the Licensee Response Column of the ROP Action Matrix. As a result of being in the Licensee Response Column, NRC oversight of Summer Nuclear Unit 1 is limited to baseline inspections.

In 2025, the NRC extended the operating license for Summer Nuclear Unit 1 to August 6, 2062.

Under the provisions of the Nuclear Waste Policy Act of 1982, on June 29, 1983, Dominion and the Authority entered into a contract (the "Standard Contract") with the Department of Energy ("DOE") for spent fuel and high-level waste disposal for the operating life of Summer Nuclear Unit 1. The Nuclear Waste Policy Act and the Standard Contract required the DOE to accept and dispose of spent nuclear fuel and high-level radioactive waste beginning no later than January 31, 1998. To date, the DOE has not accepted any spent fuel from Summer Nuclear Unit 1 or any other utility and has not indicated when it anticipates doing so.

Dominion contracted with HOLTEC International, The Shaw Group, Inc. ("Shaw"), and Westinghouse to build a licensed Independent Spent Fuel Storage Installation ("ISFSI"), which was completed and commenced receiving fuel in 2016. Because of the DOE's failure to meet its obligation to dispose of spent fuel, Dominion and the Authority are being reimbursed by DOE for a portion of ISFSI project costs. The DOE reimbursements to date equal approximately 85% of the total project costs.

The following table sets forth certain performance indicators for Summer Nuclear Unit 1 for the years 2022 through 2024, and for the period of commercial operation from January 1, 1984 through December 31, 2024. The next refueling outage is scheduled for February 20, 2026.

	2022	2023(1,2,3)	2024(4,5)	January 1, 1984 - December 31, 2024
Net Generation – MWh	8,591,103	7,515,709	7,421,165	287,801,816
Capacity Factor - %	101.5	88.8	87.5	85.3
Availability Factor - %	99.4	87.9	86.9	86.2
Forced Outage Rate - %	0.0	4.2	0.0	2.4

(1) April 5 - April 7, 2023 — 2.6 days for unscheduled outage from loss of a main feed pump and subsequent thrust bearing repair.
(2) Spring 2023 — 30 days for scheduled refueling outage.
(3) May 7 - May 19, 2023 — 11.6 days for unscheduled outage extension to complete maintenance and refueling activities.
(4) Fall 2024 – 35 days for scheduled refueling outage.
(5) October 26 – November 1, 2024 – 6.8 days for unscheduled outage extension to complete additional maintenance scope.

Summer Nuclear Unit 1 was shut down on January 30, 2026 because of a steam leak in a feedwater heater. The piping associated with the steam leak was repaired and the plant was restored to operation on February 9, 2026.

Power Purchase Agreements or Purchases

The Authority presently receives 84 MW of firm supply from the U.S. Army Corps of Engineers and 305 MW of firm hydroelectric power from SEPA. The SEPA allocation consists of 154 MW for wheeling to the SEPA preference customers served by the Authority and 151 MW purchased by the Authority for its customers. The Authority's contract with SEPA is subject to termination only after the Authority delivers a written termination notice to SEPA at least twenty-five (25) months prior to the termination date, or SEPA delivers a written termination notice to the Authority at least twenty-four (24) months prior to the termination date. The Authority may also terminate the contract in the event of a rate adjustment that would result in increased costs to the Authority.

In addition to the Authority's generation facilities, the Authority enters into various power purchase arrangements through which the Authority purchases additional capacity and energy. The following chart describes power purchase and capacity agreements entered into by the Authority.

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Power Purchase Agreements

Number and Type	Capacity/Energy	Fuel Source	Online Date	Term (years)
3 PPAs	74 MW of capacity and energy	Biomass	2010-2013	15 to 30
1 Agreement to Purchase Output	2.5 alternate current MW solar photovoltaic	Solar	2013	20
4 PPAs	280 MW to comply with PURPA requirements	Solar	2020-2023	5
2 PPAs[1]	200 MW of Solar	Solar	2025	20
2 PPAs	250 MW of capacity with optional energy	Natural Gas 80% Coal/Oil/Other Resources 20%	2024	5
1 PPA	150 MW of capacity and energy	Nuclear	2025	4
1 Short-Term PPA[2]	47 MW of capacity	Oil/Diesel	2023-2025	Less than 1

[1] The Authority is entitled to 27.5% of this output; Central is entitled to 72.5% of the output.
[2] Represents a series of short-term PPAs that are each less than 1 year in length.

As required by Section 58-31-227 of the South Carolina Code of Laws, in November 2022, the Authority filed for SCPSC approval of a program for the competitive procurement of renewable energy ("CPRE"). The SCPSC approved this program on January 3, 2024 (Docket no. 2022-351-E; Order No. 2024-2). Following the guidelines established in the approved CPRE program, the Authority issued the required notices and then issued a Request for Proposals ("RFP") on June 10, 2024. The RFP requested proposals for energy and associated renewable and environmental attributes produced from solar PV resources. The results of the 2024 Solar RFP are discussed in "Power Resource Additions" below.

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Fuel Supply and Risk Management

During 2024, the Authority's energy supply, including energy wheeled to SEPA preference customers, was derived from the following fuel sources:

Source of Power Supply (Energy)	% of Total (MWh)
Coal	41.5%
Natural Gas and Oil	20.9
Nuclear	9.3
Hydro	1.7
Other Owned Renewables	0.2
Purchases:	
Renewable	5.2
Other	21.2
Total	100.0%

Coal. The Authority contracts for bituminous coal from three primary coal basins: Central Appalachia, Northern Appalachia, and Illinois Basin. Considering quantity and quality requirements, the Authority uses a combination of these coal supplies with long-term and short-term contracts to meet its solid fuel needs at the Winyah and Cross Generating Stations. The Authority evaluates the fuel contracts based on the lowest delivered prices, while ensuring and adapting to future needs.

The Authority has long-term contracts in place with five suppliers for 2026, four suppliers for 2027, three suppliers for 2028, and one supplier for 2029 and 2030. The Authority also has an executed agreement with a supplier to provide all make-up tons that were not previously provided during the Rate Freeze Period. With the addition of these volumes from executed contracts to existing inventory, as of December 31, 2025, the Authority has secured the following percentages of the projected coal burns for 2026-2030: 100%, 84%, 50%, 34%, and 35%, respectively. Additional coal can be acquired from spot market purchases if necessary. All the Authority's suppliers have loading facilities for providing delivery of coal in unit train shipments. The Authority owns approximately 1,700 coal cars and can supplement its fleet as needed with cars provided by the railroad and through short-term leases. The Authority will also lease out its owned cars to other parties to avoid storage charges during periods when all of its coal cars are not needed for planned shipments. The Authority's rail transportation contract is in effect through December 31, 2030 (executed contract extension effective July 1, 2025). The Authority will be negotiating an extension of this contract prior to the termination date of this agreement. The rail transportation contract has a fuel surcharge clause that requires the Authority to pay the retail diesel price overage beyond the base charge; this exposure is mitigated by use of a heating oil financial futures hedge program. Heating oil is a close proxy for retail diesel. Based on the most recent projection of exposure to retail diesel via rail miles traveled, the current heating oil coverage level is 26% for 2026.

The Authority uses a methodology that reflects the impact of coal to gas switching to calculate its coal days on hand. This methodology for calculating coal days on hand uses the annual amount of coal budgeted to be burned divided by 365. The annual burn budget factors in coal to gas generation switching based on economics, using projections based on gas prices and forward price curves available at the time the budget is developed. Using this methodology, the Authority had approximately 51 days of coal on hand as of September 30, 2025, based on average daily burn projected for 2026.

Sulfur dioxide ("SO_2") air emission limitations dictate the maximum amount of coal sulfur content that can be used by generating units. The sulfur content of coal received under existing contracts ranges from approximately 0.9% to 3.0%. See "REGULATORY MATTERS – Environmental Matters."

Natural Gas. The Authority uses its Firm Transportation contracts as well as short-term and daily pipeline capacity purchases on the market to ensure delivery of natural gas to its plants. The Authority contracted with Transco to provide firm gas transportation on the SouthCoast Expansion for 80,000-MMBtu/day, the amount approximately equal to the combined cycle unit of the Rainey Generating Station at full load. The fixed rate contract expired on October 31, 2015; however, a service agreement for the same volume is in effect through November 1, 2031, and thereafter on a year-to-year basis at the tariff rate. The current SouthCoast tariff rate is $0.13540 per dekatherm which includes a base reservation rate of $0.13240 that is likely to remain in effect until the current rate case, filed on August 30, 2024, at FERC Docket No. RP24-1035 is settled or finally adjudicated, and an electric power unit rate of $0.00300 that changes approximately annually. The fixed reservation charge is paid regardless of use. Variable charges are incurred as physical nominations of natural gas are scheduled to flow.

Additionally, the Authority has signed a Precedent Agreement with Transco for an additional 80,000-MMBtu/day of firm gas transportation, to serve both Rainey and Cherokee, on the proposed Southeast Supply Enhancement project with an expected in-service date of November 1, 2027.

Any additional gas transportation necessary to fuel the remaining needs of the units at the Rainey or Cherokee Generating Stations will be purchased on the spot market as needed.

The Authority won a capacity release bid on Carolina Gas Transmission via the asset manager for IP Georgetown called IGS Energy Marketing for rights to 5,700-MMBtu/day firm natural gas pipeline transportation to the Winyah Generating Station in Georgetown for use by the planned LM6000 aeroderivative combustion turbine resources. The term began October 1, 2025, and will extend four years on the existing contract before rolling into allowable contract extensions; however, the capacity will be re-released to market participants until the interconnection and metering station for the LM6000 units become operational.

Fuels Risk Management. The Board has approved a policy governing activities related to the Authority's fuels risk management program. The Authority strives to mitigate variations in price with a combination of long-term and short-term contracts, a hedging program, and by taking advantage of market opportunities, such as purchasing and blending off-specification coal when the economics are favorable. The Authority has determined that TEA will execute transactions as outlined by the policy's procedures. See "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES – The Energy Authority." The Authority purchases the majority of its physical natural gas on a daily or short-term basis. Based on the most recent projection of natural gas volume requirements of Rainey and Cherokee units, the level of natural gas commodity hedged by way of forward financial positions, as of December 2, 2025, is 69% for 2026, 40% for 2027, 6% for 2028, 2% for 2029, 2% for 2030, and 2% for 2031. The Authority also has natural gas exposure by way of various purchase power agreements which are in effect through 2028. The hedge coverage for such agreements is 31% for 2026 and 9% for 2027. The Authority also hedges exposure to retail diesel fuel used in coal deliveries. See "*Coal*" above. On September 19, 2024, the Authority's Executive Energy Management Committee ("EEMC") approved a new product called Prepaid Natural Gas ("PNG"). By partnering with other tax-exempt municipal entities, through a Joint Action Agency who issues bonds, the Authority can contract with a supplier for delivery of must-take PNG at a discount to the daily market prices as long as the natural gas is being used for our Qualified Use customers (retail load). A North American Energy Standards Board ("NAESB") agreement with Municipal Gas Authority of Georgia, a Joint Action Agency, was required to execute any specific transactions which can be short-term or long-term (30-year terms have 5-to-7-year re-pricing periods and temporary and permanent remedies to exit the transaction). The Authority has entered several short-term transactions for various amounts and Terms and a long-term transaction on 10,000-MMBtu/day of the 80,000-MMBtu/day pipeline capacity at Rainey. The short-term transactions generally have a discount of $0.05/MMBtu. The long-term transaction has a term of April 2025 through March 2055 with a discount of $0.52/MMBtu for the initial pricing period which will be repriced after 7 years. The cost of commodity and delivery variables remain open to the market; however, traditional financial hedging tools can be used to secure those exposures.

System Risk Mitigation. The following table takes into consideration the Authority's exposure to all types of fuel and energy used to serve its load, as projected in the 2026 Budget Dispatch. It includes previously described commodity coverages for volumes of natural gas, coal, coal transportation surcharge, and purchased power agreements. It also includes the coverage of associated costs. Most of the remaining cost exposure is due to purchased power agreements that have a floating price, natural gas transportation costs that are normally not secured until the day before expected usage, and coal transportation. See above "*Coal*", "*Natural Gas*", "*Commodity Risk Management*", and "– Power Purchase Agreements or Purchases."

	2026		2027		2028		2029		2030		2031	
	Coverage		Coverage		Coverage		Coverage		Coverage		Coverage	
	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost	Volume	Cost
Coal	93%	89%	59%	68%	50%	63%	34%	54%	35%	55%	0%	0%
Natural Gas	69%	64%	40%	38%	6%	16%	2%	13%	2%	13%	2%	13%
Purchased Power-Energy	70%	39%	55%	29%	65%	33%	14%	12%	18%	18%	16%	15%
System Overall	84%	69%	58%	49%	46%	43%	28%	34%	28%	35%	13%	8%

* Data shown is projected as of December 2, 2025.

Nuclear. Under the Joint Ownership Agreement for Summer Nuclear Unit 1, Dominion acts for itself and as agent for the Authority in the operation of Summer Nuclear Unit 1 including the acquisition and management of nuclear fuel. Contracts and enriched uranium inventory are in place to supply uranium and conversion services requirements through 2030. Contracts and enriched uranium inventory are in place to supply enrichment service requirements through 2032.

Market Power Purchases. The majority of the Authority's market purchases come from TEA but also include PMPA, SEPA, the Southeast Energy Exchange Market ("SEEM"), and renewable PPAs.

Transmission

The Authority operates an integrated transmission system which includes lines owned by the Authority as well as those owned by Central and maintained by the Authority. The transmission system includes approximately 1,480 miles of 230 kilovolt ("kV"), 1,979 miles of 115 kV, 1,761 miles of 69 kV, and 40 miles of 34 kV and below overhead and underground transmission lines. The Authority operates 93 transmission substations and switching stations serving 97 distribution substations and 427 Central delivery points. The Authority plans the transmission system to operate during normal and contingency conditions that are outlined in electric system reliability standards adopted by the North American Electric Reliability Corporation ("NERC").

Broadband Access

As part of the statewide initiative, the Authority is working with State agencies and private companies to utilize its transmission lines and excess fiber to assist with the delivery of broadband internet to rural areas in the State. The Authority will not provide internet service or act as an Internet Service Provider but is accepting applications for dark fiber leasing and pole attachments from organizations that do provide internet service. The Authority has entered into a signed agreement with one electric cooperative to assist with the delivery of internet service.

Distribution

The Authority owns distribution facilities in two service areas: (i) the Berkeley District serving retail customers in St. Stephen, Bonneau Beach, Moncks Corner and Pinopolis, and some unincorporated and rural areas in Berkeley County, along with a small parcel in Charleston County; and (ii) the Horry-Georgetown Division serving retail customers in Conway, Myrtle Beach, North Myrtle Beach, Loris, Briarcliffe, Surfside Beach, Atlantic Beach, Pawleys Island, unincorporated areas along the Grand Strand and portions of rural Georgetown and Horry Counties. See "CUSTOMER BASE."

General Plant

The Authority owns general plant assets consisting of office facilities; transportation and heavy equipment; computer equipment; and communication equipment necessary to support the Authority's operations. The general plant includes all buildings associated with supporting the operations of the Authority throughout the State. These buildings range from a main office complex in Moncks Corner and an office facility in Myrtle Beach to multiple warehouses, crew quarters, transportation service buildings, and various other service buildings.

Interconnection and Interchanges

The Authority's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with Dominion at twelve locations; with Duke Energy Progress at eight locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Energy Carolinas, at two locations. The Authority is also interconnected with Dominion, Duke Energy Carolinas, Southern Company, and SEPA through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, the Authority's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. The Authority has separate interchange agreements with each of the companies with which it is interconnected to provide for mutual exchanges of power.

Reliability Agreements

The Authority is a party to the Carolina Reserve Sharing Group ("CRSG") Agreement, which exists to safeguard the reliability of the CRSG region by pooling and sharing operating capacity reserves. Other parties to this agreement are Duke Energy Progress, Duke Energy Carolinas, and Dominion.

The Authority is also a member of the SERC Reliability Corporation, which is one of six regional entities under NERC, and a member of the VACAR South sub region. The VACAR South sub region is comprised of the Authority, Duke Energy Progress, Duke Energy Carolinas, Dominion, and Cube Hydro Carolinas LLC. VACAR South safeguards the reliability of the region by coordinating the planning and operation of the regional bulk electric system.

The Energy Authority

The Authority is a member of TEA, a governmental nonprofit power marketing corporation. In addition to the Authority, the current members of TEA include City Utilities of Springfield (Missouri), Jacksonville Electric Authority (Florida), Nebraska Public Power District, American Municipal Power, Inc. (Ohio), and the Grand River Dam Authority (Oklahoma). TEA is engaged in buying and selling wholesale electric power and procuring natural gas for its members for use in their operations and also serves as members' market participant in various regional transmission organizations, to maximize the efficient use of energy resources, reduce operating costs, and increase operating revenues of its members without impacting the safety and reliability of their electric systems. TEA's revenues and costs are allocated to members pursuant to settlement procedures under TEA's operating agreement.

As of September 30, 2025, the Authority had an approximate 18.75% ownership interest in TEA and the Authority accounts for its investment in TEA under the equity method of accounting. As a member of TEA, the Authority pays a membership fee and makes certain contributions to capital and is providing certain guarantees in an amount not to exceed $115 million for electric and gas trading by TEA as of September 30, 2025. If any payment is required to be made to TEA by the Authority, it will be payable as an operation and maintenance expense under the Revenue Obligation Resolution. All of TEA's revenues and costs are allocated to the members. As of September 30, 2025 and December 31, 2024, the Authority's share of monthly revenues over expenses from the Authority's investment in TEA was $0.4 million and $1.8 million, respectively. For additional information, see "M – Investment in Associated Companies" under Note 1 in APPENDIX A – "Report of the Authority's Financial Statements" attached hereto.

Southeast Energy Exchange Market

The Authority is a participant in SEEM, a region-wide, integrated, automated, intra-hour energy exchange platform. SEEM matches buyers and sellers of energy with the goal of more efficient bilateral trading utilizing unused transmission capacity to achieve cost savings for customers. Other founding members of SEEM include Associated Electric Cooperative, Dalton Utilities, Dominion, Duke Energy Carolinas, Duke Energy Progress, Georgia System Operations Corporation, Georgia Transmission Corporation, Louisville Gas & Electric and Kentucky Utilities Energy (KU), Municipal Electric Authority of Georgia Power (MEAG), North Carolina Municipal Power Agency No. 1, North Carolina Electric Membership Corporation (NCEMC), Oglethorpe Power Corp., PowerSouth, Southern Company, and Tennessee Valley Authority. The Southeast Energy Exchange Market Agreement among SEEM and the prospective members was deemed approved by operation of law by FERC on October 12, 2021, and became operational on November 9, 2022. On July 14, 2023, the United States Court of Appeals for the District of Columbia Circuit granted in part and denied in part a petition for review of FERC's interrelated SEEM orders, including vacating FERC's deemed approval and remanding the matter back to FERC for further action. On March 14, 2025, FERC issued its Order on Remand reaffirming its initial approval of SEEM.

Integrated Resource Planning

Integrated Resource Plan

The Authority develops Integrated Resource Plans (IRPs) as part of its overall planning process. The IRP process evaluates the Authority's existing generation resources alongside its projected load and energy needs over an extended period. It establishes a plan for the resources necessary to meet these needs. As per revisions to S.C. Code Ann. § 58-37-40, the Authority is now required to prepare an IRP and submit it to the SCPSC every three years, with updates in the intervening years. Additionally, the Authority must establish a process for receiving stakeholder input during the development of its IRP. Each IRP will outline a roadmap for how the Authority plans to meet its customers' projected load cost-effectively and reliably. This requires balancing multiple objectives, including system reliability, environmental responsibility, cost impacts, and risks. The IRP must be developed in consultation with electric cooperatives, including Central, and municipally owned electric utilities that purchase power and energy from the Authority. The Authority is also expected to consider any feedback provided by retail customers.

The 2023 Integrated Resource Plan

The 2023 Integrated Resource Plan (the "2023 IRP") was initially filed with the SCPSC on May 15, 2023, in docket number 2023-154-E, and was supplemented by the Authority on October 27, 2023, with an Addendum providing the results of analysis prepared in response to recommendations from the ORS. On March 8, 2024, the SCPSC issued Order No. 2024-171 approving the 2023 IRP, having determined the proposal represented the most reasonable and prudent means of meeting the Authority's energy and capacity needs as of the time the proposed IRP was reviewed. A copy of the 2023 IRP may be viewed at the following address: https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/2023-Santee-Cooper-IRP.pdf. *No statement or information on the Authority's website is incorporated by reference herein.*

The 2023 IRP identified the Authority's "Preferred Portfolio," which reflected a cost-effective approach under a wide range of assumptions and would position the Authority to adapt to potential policy changes related to CO_2 emissions.

The Preferred Portfolio includes adding substantial new solar resource capacity annually from 2026 through the 2030s, totaling approximately 1,500 MW by 2030 and over 3,000 MW by 2040; retiring the 1,150 MW Winyah Coal Generating Station by year-end 2030; developing a natural gas combined cycle ("NGCC") resource of approximately 1,090 MW to coincide with the retirement of Winyah; and adding several hundred MW of combustion turbine generating units and battery energy storage systems ("BESS") in the mid-2030s.

The 2023 IRP also outlines a short-term action plan, which includes continuing to work with Central and market participants to identify options and transmission arrangements to meet capacity needs before 2029; proceeding with further actions to implement the NGCC resource, including potential collaboration with Dominion; adding substantial solar resources through multiple procurements, targeting new capacity additions starting in 2026; further implementing attractive demand-side management programs and conducting additional studies to evaluate demand-side options; implementing a BESS resource as a pilot project to enhance familiarity with the technology; and investigating the cost and appropriate locations for future wind projects.

Each IRP, including the 2023 IRP, is developed solely as a planning document and no assurance is given as to the ability of the Authority to achieve the goals described therein.

2024 Annual Update to the Integrated Resource Plan

The Authority is required to submit annual updates to its approved IRP to the SCPSC. The annual update must include an update to the Authority's base planning assumptions relative to its most recently accepted IRP, including, but not limited to energy and demand forecast, commodity fuel price inputs, renewable energy forecast, energy efficiency and demand-side management forecasts, changes to projected retirement dates of existing units, along with other inputs the SCPSC deems to be for the public interest. The Authority's annual update is also required to describe the impact of updated base planning assumptions on the selected resource plan. The ORS reviews the Authority's annual update and will submit a report to the SCPSC providing a recommendation concerning the reasonableness of the annual update. The SCPSC may accept the annual update or direct the Authority to make changes to the annual update that the SCPSC determines to be in the public interest.

The Authority filed the 2024 annual update to the IRP on September 16, 2024, at docket number 2024-18-E. On May 1, 2025, the SCPSC issued Order No. 2025-244 accepting the 2024 IRP Update, having determined the IRP Update is reasonable and finds that it meets the statutory requirements.

In conjunction with this annual update, the Authority formed a Stakeholder Working Group with participants representing a wide range of interests and perspectives. The intent is to create an open dialogue and provide a forum for deep technical discussion of the analytical work supporting the IRP. The Authority will also continue to hold general Stakeholder sessions, open to the public, and publish meeting presentations and materials on the Authority's website on the integrated resource plan page located at the following address: https://www.santeecooper.com/About/Integrated-Resource-Plan/Index.aspx. *No statement or information on the Authority's website is incorporated by reference herein.*

The 2024 annual update includes an updated load forecast with substantial load growth from new and existing large customers, a significant portion of which is related to data centers and battery manufacturing facilities. During development, the Authority tracked 25 potential customers who expressed a desire to receive service directly from the Authority or indirectly through the Authority's wholesale customers, with a potential aggregate peak demand of approximately 3,500 MW. After careful evaluation of these potential loads, the Authority made an adjustment to the load forecast of approximately 1,100 MW (winter peak) by 2033.

The 2024 annual update confirms the primary conclusions reached in the 2023 IRP regarding the need for a large NGCC resource, substantial new solar resources, and the need for combustion turbine and battery energy system storage to meet system peaking needs. Due to the increase in load growth, the 2024 annual update identifies resource additions beyond those recommended in the 2023 IRP. These resources consist of additional capacity opportunities at the existing Rainey Generating Station and acceleration and addition of more peaking capacity through combustion turbine, battery energy storage system, and power purchase agreement resource options. The 2024 annual update can be viewed on the Authority's website on the integrated resource plan page located at the following address: https://www.santeeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2024-IRP-Update.pdf. *No statement or information on the Authority's website is incorporated by reference herein.*

2025 Annual Update to the Integrated Resource Plan

The Authority filed the 2025 annual update to the IRP on September 16, 2025, at docket number 2025-18-E. The Authority continued to work with the Stakeholder Working Group formed during the 2024 IRP Update and hold general Stakeholder sessions, open to the public, and publish meeting presentations and materials on the Authority's website on the integrated resource plan page located at the following address: https://www.santeecooper.com/About/Integrated-Resource-Plan/presentations/Santee-Cooper-2025-IRP-Update.pdf. *No statement or information on the Authority's website is incorporated by reference herein.*

On January 26, 2026, the Authority submitted comments in response to the "Review of South Carolina Public Service Authority's (Santee Cooper) 2025 Integrated Resource Plan Update" prepared by ORS and filed with the SCPSC on December 15, 2025 in Docket No. 2025-18-E, and the "Joint Comments of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club" filed with the SCPSC on January 13, 2026, and the Authority requested that the SCPSC accept the 2025 IRP Update.

The 2025 IRP Update confirms many of the primary conclusions reached in the 2023 IRP and 2024 IRP Update regarding preferred resource additions to the power supply resources and bulk transmission network of the Authority and Central (the "Combined System") portfolio, indicating that the following resources should be pursued:

- Development of the Joint NGCC facility to provide approximately 1,090 MW by 2033.
- Addition of natural gas combustion turbine ("NGCT") capacity and/or BESS to meet system peaking needs beginning in the late 2020s.
- Continued and regular addition of solar resources to enhance portfolio diversity and mitigate risks, with consideration of recent changes in federal laws and tax policy.

Similar to changes in assumptions modeled for the 2024 IRP Update, the load to be served by the Combined System is projected to exceed the values assumed in the 2023 IRP, necessitating considerably greater resource additions than those recommended in the 2023 IRP. These additional resources include the following:

- Conversion of Rainey Generating Station's ("Rainey") combustion turbine units 2A and 2B to combined cycle operation (adding approximately 178 MW by 2028), along with upgrades to other combustion turbine and combined cycle resources at Rainey (estimated to add approximately 71 MW by 2028, and when combined with the additional capacity expected to be added from the conversion will result in an estimated increase in total of approximately 249 MW by 2028).
- Addition of 300 MW of BESS capacity by 2029.
- Addition of 107 MW of LM6000 aeroderivative combustion turbine resources by 2028.
- Addition of two 1x1 NGCC resources totaling 1,296 MW by 2035.

As a result of the OBBBA (as defined herein) provisions accelerating the phase-out of tax credits for solar and wind resources, the projected net cost of these resources to the Authority will be substantially higher than previously expected in the 2023 IRP and 2024 IRP Update. See "REGULATORY MATTERS – Inflation Reduction Act and OBBBA." However, recognizing that these resources offer benefits such as fuel diversity, reduced carbon risk, and improved environmental performance, the Authority plans to regularly evaluate the renewable market and add them to the portfolio when deemed cost-effective for customers.

Power System Additions

South Carolina law imposes certain limitations and approval requirements on the Authority with respect to the planning and development, construction, or acquisition of a major utility facility. In addition, the SCPSC must approve the construction or acquisition of a major utility facility, but only to the extent that the transaction is not subject to the FERC's exclusive jurisdiction. A 'major utility facility' is defined under existing statutes as an electric generating plant and its associated facilities designed for operation at a capacity of more than 75 MW, or an electric transmission line and associated facilities with a designed operating voltage of 125 kV, or more, but does not include electric distribution lines and associated facilities.

On January 30, 2025, the SCPSC granted the Authority an Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity ("CECPCN") for the construction and operation of a steam turbine generator and associated facilities at the existing Rainey Generating Station in docket number 2024-264-E. The project will convert two existing combustion turbines into a 2x1 natural gas combined cycle turbine, expected to add 178 MW of incremental winter capacity.

On August 28, 2025, the Authority filed an Application for a CECPCN for the construction and operation of two GE Vernova LM6000 aeroderivative combustion turbines and associated facilities at the existing Winyah Generating Station in docket number 2025-246-E. These resources will utilize a dual-fuel, dry, low-nitrogen oxide ("NOx") combustion system, enabling the units to operate on both natural gas and fuel oil while minimizing NOx emissions without the need for water or steam injection. Each unit is rated to produce approximately 54 MW. On January 8, 2026, the SCPSC approved the application and the Authority is currently awaiting entry of the order.

The Authority began a competitive procurement process in March 2025 for up to 300 MW of four-hour BESS to be located at the Jefferies Generation Station site, which was formerly home to coal and oil generation units. In November 2025, the Authority selected AYPA Power Development LLC to build, own, and operate 300 MW of BESS on property leased from the Authority under a 20-year services agreement. This project is expected to be energized by December 2027. This battery storage project marks a significant step in modernizing the Authority's energy resource mix and improving grid reliability.

Pursuant to South Carolina Act 41, the Authority has been jointly planning a multi-unit natural gas-fired advanced-class combined cycle generation plant, known as the Joint NGCC, with Dominion. In October 2025, the Authority and Dominion executed a joint ownership agreement relating to the Joint NGCC. The new plant will consist of three (3) advanced-class combined-cycle units with a total capacity of approximately 2,180 MW. The Authority would own a 50 percent share, or approximately 1,090 MW. The total project cost for the new plant is currently estimated to be $5 billion with the Authority's portion expected to be one-half of that cost. The Joint NGCC will be located on Dominion's former Canadys Station site in Colleton County, South Carolina. Construction and operation of the Joint NGCC is subject to review and approval by the SCPSC under the South Carolina Utility Facility Siting and Environmental Compatibility Act ("Siting Act"). On December 15, 2025, the Authority and Dominion filed an application with the SCPSC under the Siting Act seeking a CECPCN to construct and operate the Joint NGCC. The Joint NGCC will use a current brownfield site and will advance the economy and serve the general welfare of the state. The Authority and Dominion have entered into an agreement for a natural gas pipeline to be built by Kinder Morgan to supply the gas for the Joint NGCC. Construction of the pipeline requires approvals from various federal and state agencies, including, among others, FERC, the South Carolina Department of Natural Resources and SCDES (as defined herein).

In addition, the Authority may not enter into a contract for the purchase of power with a duration longer than ten years without approval of the SCPSC, provided that the approval is required only to the extent the transaction is not subject to the exclusive jurisdiction of FERC or any other federal agency. Approval of such a contract is not required for purchases of renewable power through the commission-approved CPRE process. In June 2024, the Authority issued an RFP for solar resources through the CPRE. A total of 32 proposals were submitted by 20 different developers, representing approximately 3,058 MW of nameplate capacity. The Authority and Central jointly selected two projects totaling 212 MW. In September 2025, the Authority and Central signed a PPA for the output of the future Magnolia solar project (42 MW). As of November 2025, the Authority and Central have not yet finalized a PPA for the remaining 170 MW project selected in the 2024 CPRE solicitation.

NUCLEAR UNITS

Regulatory Accounting

On July 31, 2017, the Authority approved the wind-down and suspension of construction of the Nuclear Units 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 at the time of the suspension.

Except for 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 the Nuclear Units were determined in accordance with GASB No. 42 to be impaired.

Based on the results of a fair value determination of the assets, the write-off of the construction costs and fuel for the Nuclear Units 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 the costs of the Nuclear Units were 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 is being recorded as a regulatory asset and amortized through November 2056 to align with the principal payments on the associated indebtedness.

In December 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 the Nuclear Units (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 – 2024 Amortization	2018 - 2024 Changes	2024 Ending Balance
Nuclear impairment	Asset	$4.211 billion	($608.3 million)	($40.2 million)	$3.563 billion
Nuclear post-suspension interest	Asset	$37.1 million	($439,000)	-	$36.7 million
Toshiba Settlement Agreement	Deferred Inflow	$898.2 million	($687.8 million)	$13.8 million	$224.2 million

For additional information regarding the accounting treatment of the Nuclear Units assets, see "Regulatory Accounting Treatment" under Note 7 – Summer Nuclear Station in APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS" attached hereto.

Sales of Nuclear Units Assets. Since 2018, the Authority has sold certain equipment and commodities located at the Summer Nuclear Station to third parties. As of September 30, 2025, $149.6 million of such materials had been sold. Further sales are not currently being pursued due to the Transaction.

In January 2025, the Authority initiated a process for requesting proposals from parties interested in acquiring one or both of the Nuclear Units and the related assets, completing one or both of such Nuclear Units, or pursuing alternative uses of the equipment and/or the site. In May 2025, the General Assembly of the State of South Carolina enacted a joint resolution to encourage the Authority to issue a request for proposals to solicit proposals from entities interested in utilizing the assets associated with the Nuclear Units. The Governor of the State of South Carolina approved the joint resolution. The joint resolution encouraged the Authority to consider each bidder's proposal to complete construction of either or both of the Nuclear Units, or any other proposal related to the assets associated with the Nuclear Units, and to consider the impact that the completion of the proposal could have on South Carolinians including, but not limited to, providing relief to ratepayers.

Proposals were received by the Authority in May 2025 and were evaluated by the Authority with the assistance of advisors, focusing on capability, credibility, commitment, and consideration, using a scoring and risk assessment framework. As a result of this process, the Authority and Brookfield entered a Letter of Intent in October 2025 that provided for a six-week exclusivity period to accomplish several efforts toward evaluating the feasibility of completing construction. In December 2025, the Authority and Brookfield executed the MOU which sets forth the principal binding and non-binding terms for the Transaction.

The non-binding terms of the MOU include:

1. If Brookfield reaches a successful final investment decision ("FID"), the Authority will receive a $2.7 billion cash payment in exchange for providing a 75% ownership interest in the Nuclear Units.

2. If Brookfield reaches a successful FID, completes the project and the Nuclear Units begin commercial operation, the Authority will receive a targeted 25% ownership interest in the Nuclear Units (as tenants in common), with proportional capacity. The Authority's ownership share (as tenants in common) could be decreased, subject to a floor, or the Authority could receive an additional cash payment at commercial operation, subject to a cap, depending on the final cost of completing the Nuclear Units.

3. By June 26, 2026 (subject to any agreed upon extensions), Brookfield will propose an economic development plan that includes (a) a commitment to using South Carolina companies and labor force, (b) partnerships with South Carolina's K-12 and higher educational institutions and investment in workforce development for residents of South Carolina, (c) working with the South Carolina Department of Veterans' Affairs to provide opportunities to military veterans, and (d) engagement with the community, including Fairfield County, and other stakeholders to provide support for community development in Fairfield County.

The binding terms of the MOU include:

1. Establishing an exclusive and formal feasibility period and timeline for Brookfield to reach FID. Brookfield will meet certain milestones and provide monthly progress reports to the Authority throughout the feasibility period.

2. By June 26, 2026 (subject to any agreed upon extensions), Brookfield must determine initial feasibility and establish a target date for FID.

3. A feasibility committee, comprised of two members each from the Authority and Brookfield with the Authority appointing the chair, will oversee the due diligence process.

4. The Authority will be reimbursed for its expenses incurred in connection with the Transaction, whether incurred prior to or after execution of the MOU and until termination of the MOU.

5. Among other termination rights, the Authority has the option to terminate the MOU if Brookfield proposes changes to certain of the non-binding terms.

The time frame to reach FID is estimated to be 18 to 24 months. If the $2.7 billion cash payment is received by the Authority pursuant to the MOU, the Authority currently expects to apply such amount to pay or defease portions of the Authority's outstanding tax-exempt bonds that are allocable to expenditures for the Nuclear Units.

The Authority is unable to predict the outcome of the feasibility period, including whether the Transaction will be ultimately consummated. No assurance can be given that Brookfield will reach a final investment decision, that definitive agreements for Brookfield to acquire and proceed with construction of the Nuclear Units will be executed, or that construction on the Nuclear Units will be completed.

The foregoing discussion of the MOU is an abstract only, and reference is made to the MOU for full and complete statements of its provisions. A copy of the MOU is available at the following address: https://www.scnuclear.com/project-overview. *The information available at the preceding website is not incorporated by reference herein*.

REGULATORY MATTERS

Environmental Matters

Both the U.S. Environmental Protection Agency (the "EPA") and the South Carolina Department of Environmental Services ("SCDES")* have imposed various environmental regulations and permitting requirements affecting the Authority's facilities. These regulations and requirements relate primarily to the emission of regulated air pollutants, the discharge of pollutants into waters, the disposal of solid and hazardous wastes, and the establishment of drinking water standards, although the addition of new facilities and other projects and operations can also cause potential impacts associated with land disturbance, wetlands, wildlife, and threatened and endangered species. The Authority endeavors to ensure its facilities comply with applicable environmental regulations and standards; however, no assurance can be given that normal operations will not encounter occasional technical difficulties or that necessary permits and authorizations will be received. Federal and state standards and procedures that govern control of the environment, systems operations, and new facilities construction can change. These changes may arise from legislation, regulatory and executive actions, and judicial interpretations regarding the standards, procedures, and requirements for compliance and issuance of permits. In addition, changes in presidential administrations and executive actions can impact legal and regulatory interpretations as well as enforcement priorities. Therefore, there is no assurance that units in operation, under construction, or contemplated will remain subject to the regulations that are currently in effect. Furthermore, changes in environmental laws and standards may substantially increase capital and operating costs.

Air Quality

General Regulatory Requirements. The Authority is subject to a number of federal and state laws and regulations addressing air quality. Pursuant to the Clean Air Act ("CAA"), as amended, the EPA promulgated primary and secondary national ambient air quality standards ("NAAQS") with respect to certain air pollutants, including particulate matter, ozone, SO_2, and NOx. These standards are to be achieved by the application of control strategies included in state implementation plans that must be approved by the EPA. South Carolina adopted its EPA-approved State Implementation Plan ("SIP") in 1972, which has since undergone numerous amendments and is generally designed to achieve primary and secondary NAAQS. The EPA also promulgated New Source Performance Standards ("NSPS") regulations establishing stringent emission standards for particulate matter, SO_2, and NOx emissions for fossil-fuel fired steam generators. Congress has enacted comprehensive amendments to the CAA, including the addition of a program to address acid precipitation caused by SO_2 and NOx emissions.

Evolving Regulatory Requirements

Greenhouse Gases. On May 9, 2024, the EPA published a final rule establishing various guidelines for greenhouse gas ("GHG") emissions from existing fossil fuel-fired steam electric generating units ("EGUs") pursuant to its authority under the CAA. For existing coal-fired steam EGUs, the EPA determined that carbon capture and sequestration technology ("CCS") with a 90% capture rate is the best system of emission reduction ("BSER"); affected EGUs must comply with this requirement on or prior to January 1, 2032. If a coal-fired steam EGU will cease operations by January 1, 2039, then its BSER is to

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* Effective July 2024, SCDES succeeded the South Carolina Department of Health and Environmental Control ("DHEC") as the South Carolina environmental regulatory agency.

co-fire with natural gas at a level of 40% of the unit's annual heat input; the compliance deadline for those EGUs is January 1, 2030. If a coal-fired steam EGU will permanently shut down by January 1, 2032, it is exempt from these requirements. The final rule became effective on July 8, 2024.

The EPA's final rule published May 9, 2024, also established NSPS for GHG emissions from new, modified, and reconstructed fossil fuel-fired EGUs. Under the rule, EPA categorized combustion turbines as either base load, intermediate load, or low load. For base load turbines (*i.e.*, units operating above a 40% capacity factor), the BSER is: (i) highly efficient combined cycle generation (based on the emissions of best performing units); and (ii) CCS technology with a 90% capture rate. The CCS requirement has a compliance deadline of January 1, 2032. For intermediate load facilities (*i.e.*, units operating above a 20% and at or below a 40% capacity factor), the BSER is highly efficient simple cycle generation. For low load facilities (*i.e.*, units, those operating at a 20% or less capacity factor), the BSER is the use of lower-emitting fuels. Under the final rule, the EPA deferred GHG emissions guidelines for existing gas-fired power plants. The final rule became effective on July 8, 2024.

On June 17, 2025, the EPA published a proposed rule to repeal all GHG emissions standards for fossil fuel-fired power plants. In the proposed rule, EPA provides two pathways. The primary proposal is a full repeal of the rules, asserting that the CAA requires a finding that GHG emissions from these power plants "contribute significantly" to dangerous air pollution as a prerequisite to regulation and that such emissions do not meet that standard. Via this path, both the 2024 and the prior 2015 rules would be repealed. In the second pathway, EPA proposes a partial repeal, asserting, in part, that CCS cannot be considered BSER for existing long-term coal-fired steam generating units as it has not been adequately demonstrated and that 40 percent natural gas co-firing cannot be considered BSER for existing medium-term coal-fired steam generating units because it is inefficient and is impermissible "generation shifting" in violation of the Supreme Court decision in the *West Virginia vs. EPA* case. The proposed partial repeal would remove CO_2 emissions standards for existing coal-fired EGUs and Phase 2 (CCS) requirements for new natural gas plants. In this second pathway, the EPA proposes to retain the Phase 1 emissions limits for new natural gas generation. The Authority will continue to evaluate and assess the impacts of this rule upon finalization.

Mercury and Air Toxics Standard. On May 7, 2024, the EPA published its final rule updating its National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired EGUs, commonly known as Mercury and Air Toxics Standards ("MATS"). The rule sets new lower limits on filterable particulate matter for coal-fired power plants and requires that all coal- and oil-fired EGUs use continuous monitoring systems for particulate matter to demonstrate compliance with the new standards. The rule tightens the particulate emission standard by lowering the emission limit of particulate matter to one third the current limit. Numerous states jointly filed a legal challenge to the rule on May 8, 2024.On June 17, 2025, the EPA published a proposed repeal of the 2024 MATS update. On December 23, 2025, EPA submitted a draft of the final action for review; EPA expects the action to be finalized by early 2026. If finalized, the particulate emission standard would revert to the previous higher limit. The Authority will continue to evaluate and assess the impacts of this rule upon finalization.

Water Quality

General Regulatory Requirements. The Authority is subject to a number of federal and state laws and regulations which address water quality. 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. SCDES has been delegated NPDES permitting authority by the EPA under the CWA and administers the program for the State. Industrial wastewater discharges from all stations and the regional water plants are governed by NPDES permits. SCDES also has permitting authority for stormwater discharges, and the Authority manages stormwater pursuant to SCDES-issued Industrial General Permits and Construction General Permits.

Evolving Regulatory Requirements

316(b) Fish Protection Regulations. Regulations implementing Section 316(b) of the CWA became effective on October 14, 2014, and require that NPDES permits for facilities with cooling water intake structures ensure that the structures reflect the Best Technology Available ("BTA") to minimize adverse environmental impacts from impingement and entrainment of fish, shellfish, and other aquatic organisms. In some cases, SCDES includes requirements in NPDES permits to conduct entrainment studies, to evaluate the potential for aquatic organisms to be drawn into the cooling water intake structures, where additional data is needed. SCDES declined to require new entrainment studies in the Rainey and Cross Generating Station permits and requested data from previously-completed entrainment studies. However, in the final permit effective in July 2025, SCDES is requiring an entrainment study at Winyah Generating Station. Entrainment study costs are assumed to be minimal. At this time the Authority does not anticipate material modifications at the Rainey, Cross, and Winyah facilities to comply with these regulations.

On July 6, 2022, the EPA issued a memorandum with a revised framework for applying Section 316(b) of the CWA to cooling water intake structures at hydroelectric facilities. No regulatory actions are expected in the near term due to the issuance of the memorandum. SCDES renewed the Hydroelectric Generating Facilities General Permit on January 1, 2026. At this time the Authority does not anticipate significant compliance or financial impacts in connection with its hydroelectric facilities.

Effluent Limitation Guidelines. On October 13, 2020, the EPA published a rule revising the Effluent Limitations Guidelines ("ELG") for the steam electric power generating point source category for flue gas desulfurization ("FGD") wastewater and bottom ash transport water ("BATW"). The FGD treatment systems and equipment required to comply with the rule using Best Available Technology Economically Achievable ("BAT") is now in operation at Cross and Winyah at a cost of $156 million and $150 million, respectively. ELG requirements under the 2020 rule, along with any new state-defined limits, were included in revised NPDES discharge permits for Cross and Winyah. The Cross NPDES permit was issued on February 1, 2024, and became effective on March 1, 2024. The Winyah NPDES permit was issued May 1, 2024, and became effective July 1, 2025.

On May 9, 2024, the EPA published revised ELGs for the steam electric power generating point source category applicable to FGD wastewater, BATW, and legacy wastewater at existing sources, and combustion residual leachate ("CRL") at new and existing sources. This rule established a zero-discharge limitation for all pollutants in FGD wastewater, BATW, and CRL as soon as possible, but no later than December 2028. The 2024 limits are in addition to the 2020 ELG limits, and the Authority estimates an additional cost of $250,000,000 per facility in capital expense to comply. The 2024 BAT standard of zero-discharge is based on membrane filtration, thermal evaporation, and spray dryer evaporation alone or in any combination including any necessary pretreatment or post-treatment. The rule also establishes a limit for mercury and arsenic for CRL discharged through groundwater and for "legacy wastewater" discharged from surface impoundments that have not commenced closure under the CCR regulations as of July 8, 2024. Coal-fired steam EGUs that will permanently cease coal combustion by December 2034 are exempt from the rule and must continue to comply with previous ELGs. The rule also requires facilities to create and maintain an ELG Rule Compliance Data and Information public website that makes reporting and recordkeeping information available to the public. The final rule became effective on July 8, 2024.

On December 31, 2025, EPA published a final rule (the "ELG Deadline Extension Rule") extending compliance deadlines for ELGs for the steam electric power generating point source category. The final rule moves the latest compliance date for FGD wastewater ("FGDW"), BATW, and CRL from December 31, 2029, to December 31, 2034. The Notice of Planned Participation ("NOPP") deadline for facilities seeking to retire coal units is extended from December 31, 2025, to December 31, 2031. It also adds new rule provisions that would allow permitting authorities flexibility to extend compliance deadlines on a site-specific basis due to unexpected electricity demand. While this action does not change the zero-discharge requirements themselves, the EPA requested information on technology-based implementation challenges related to the 2024 ELG rule and will use this data to support a future rulemaking to support practical, feasible, on-the-ground implementation of wastewater pollution discharge limits. The rule will become effective on March 2, 2026.

In coordination with the release of the final ELG Deadline Extension Rule, EPA's Office of Enforcement and Compliance ("OECA") issued a No Action Assurance ("NAA") Memorandum. The NAA memo provides temporary enforcement relief for steam electric power plants that qualify for alternative compliance dates under the new Deadline Extensions Rule. EPA recognizes that facilities and permitting authorities may need extra time to update permits to reflect the new rule, given the administrative process involved. Facilities may now switch between compliance alternatives, including moving in and out of subcategories, for permanent cessation of coal combustion and zero-discharge limitations, through December 31, 2034. EPA authorizes permitting authorities to set alternative compliance and paperwork submission dates based on site-specific factors. Permitting authorities may accept late NOPP submissions provided the facility meets one of the circumstances noted in the rule. The rule also clarifies the must-run provision, including with respect to FERC's acceptance of a reliability must-run agreement.

Waters of the U.S. The definition of "waters of the United States" ("WOTUS") under the CWA is defined by regulations promulgated by the U.S. Army Corps of Engineers ("USACE") and the EPA and informed by court decisions, and it has changed over the years. On January 18, 2023, the USACE and EPA issued the final "Revised Definition of 'Waters of the United States'" rule, which took effect on March 20, 2023. On May 25, 2023, the United States Supreme Court issued a decision in *Sackett v. EPA* that narrowed the definition of WOTUS. Specifically, the Court ruled that CWA jurisdiction extends only to: (1) traditional navigable waters; (2) relatively permanent waters connected to traditional navigable waters; and (3) adjacent wetlands with a continuous surface connection to such waters. On September 8, 2023, EPA and USACE finalized a rule to conform the definition of WOTUS to the decision in *Sackett.* Due to ongoing litigation, the January 2023 Rule, as amended by the conforming rule, is not currently operative in many states, including South Carolina. These states are interpreting WOTUS consistent with the pre-2015 regulatory regime for those states. On November 20, 2025, EPA published a proposed rule to clarify the definition of WOTUS and implement the Supreme Court's Sackett decision. The Authority will await the publication of the final rule and evaluate impacts to construction projects and Authority operations.

Drinking Water

The Authority continues to monitor for Safe Drinking Water Act regulatory issues impacting drinking water systems at the Authority's Regional Water Systems, generating stations, substations, and other auxiliary facilities. SCDES has regulatory authority for public water systems in the State. The State Primary Drinking Water Regulation, R.61-58, governs the design, construction, and operational management of public water systems in the State subject to and consistent with the requirements of the Safe Drinking Water Act and the implementation of federal drinking water regulations.

On the federal level, in 2021 the EPA announced its plan to address PFAS and required monitoring for 29 PFAS in the Fifth Unregulated Contaminant Monitoring Rule (UCMR 5), issued pursuant to the Safe Drinking Water Act's requirement to issue a list of unregulated contaminants to be monitored by public water systems every five years.

On April 10, 2024, EPA finalized a National Primary Drinking Water Regulation establishing legally enforceable levels, called Maximum Contaminant Levels ("MCLs"), for six PFAS in drinking water. EPA also finalized health-based, non-enforceable Maximum Contaminant Level Goals for these PFAS. Water systems are required to complete initial monitoring for these six PFAS by 2027 and must take action to reduce the levels of these PFAS in drinking water if those levels exceed MCLs. Systems that detect PFAS above the MCLs will have five years to implement solutions that reduce PFAS in their drinking water. Granular activated carbon, anion exchange, reverse osmosis, and nanofiltration were identified by the EPA as the BAT for meeting the PFAS MCLs. Water systems may use any technology or practice to meet the PFAS MCLs and are not limited to the BATs. The new rule will impact the Lake Marion and

Lake Moultrie Water Plants and Cross Generating Station. EPA announced in May 2025 that it plans to publish proposed rules to reconsider the regulatory determinations of four PFAS (all but perfluorooctanoic acid ("PFOA") and perfluorooctanesulfonic acid ("PFOS")), extend compliance deadlines, and enhance outreach to water systems. The Authority is continuing to monitor for EPA communication of rule revisions.

On May 8, 2024, the EPA published a rule designating PFOA and PFOS as hazardous substances under CERCLA, effective July 8, 2024. The rule requires entities to immediately report releases of PFOA and PFOS that meet or exceed the reportable quantity to local emergency responders and enables cost recovery and enforcement authorities to address PFOA and PFOS releases.

In addition, the EPA's Lead and Copper Rule Revisions ("LCRR"), regulating lead and copper in drinking water, became effective on December 16, 2021, with a compliance date of October 16, 2024. On October 30, 2024, the EPA issued the Lead and Copper Rule Improvements, which superseded the LCRR but retained some of its provisions. It requires most water systems to replace lead service lines within 10 years, requires water systems to regularly update lead pipe inventories and create a publicly available replacement plan, changes tap sampling protocols, lowers the lead action level from 15 µg/L to 10 µg/L, and requires water systems to provide filters when they have multiple exceedances of the lead action level. The rule went into effect on December 30, 2024. This rule is expected to have only a minimal impact on the Authority's Regional Water Systems as they have a limited transmission system that is completely constructed from cement-lined ductile iron pipe. Cross Generating Station is required to conduct an inventory of on-site drinking water piping.

Solid and Hazardous Waste and Hazardous Substances

General Regulatory Requirements. The Authority is subject to federal and state laws and regulations which address solid, universal, and hazardous waste and substances. The Resource Conservation and Recovery Act ("RCRA"), under Subtitle C, is the overarching regulation providing the framework for proper management of hazardous waste. Additional regulations pertaining to solid and hazardous wastes and substances are: the CWA, which imposes penalties for spills of oil or federally listed hazardous substances into water and for failure to report such spills; CERCLA, which establishes reporting requirements for the release of hazardous substances into the environment and imposes liability on responsible parties for the cleanup of such substances; the Emergency Planning and Community Right-to-Know Act, which requires emergency planning and public access to information regarding hazardous chemicals; the Hazardous Materials Transportation Act, which governs the safe transportation of hazardous materials; and the Toxic Substances Control Act, which imposes stringent requirements for labeling, handling, storing, and disposing of some hazardous substances, including polychlorinated biphenyls ("PCB") and associated equipment. The Authority has comprehensive waste and PCB management programs, policies, and procedures for ongoing compliance in response to these regulations, as well as for compliance with the requirements of the other waste management statutes and regulations noted above. The Authority may have liabilities for investigation or remediation of sites that have been adversely affected by disposal of solid waste or hazardous waste or substances present on its properties.

Evolving Regulatory Requirements

Coal Combustion Residuals ("CCR") Rule. 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 or CCRs, are exempt from hazardous waste regulation under RCRA Subtitle C. On April 17, 2015, the EPA published the CCR Rule establishing comprehensive requirements for the management and disposal of CCRs from electric utilities. The rule regulates CCRs as a nonhazardous waste under RCRA Subtitle D and was effective 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.

Not all of the Authority's surface impoundments are subject to the 2015 CCR Rule. The impoundments subject to the 2015 CCR Rule are located at the Cross and Winyah Generating Stations. These CCR impoundments are closing, and as of the April 11, 2021, CCR Rule compliance deadline, all of the Authority's impoundments that are subject to the CCR Rule were no longer receiving any CCR or non-CCR waste streams.

On May 8, 2024, the EPA published a rule amending its CCR regulations for legacy CCR surface impoundments and CCR management units at active CCR facilities and at inactive CCR facilities with a legacy CCR surface impoundment (the "Legacy CCR Rule") became effective on November 8, 2024. Under the rule, EPA established standards for legacy CCR impoundments to comply with the same regulations that apply to inactive CCR impoundments at active power plants, except for the location restrictions and the liner design criteria, with tailored compliance deadlines. This will affect the Jefferies Generating Station ash pond. EPA established a more limited set of requirements—primarily post-closure care, groundwater monitoring, and corrective action, if necessary—for ponds that have already completed closure under state oversight. This will affect the Grainger Generating Station ash ponds. The rule also requires a two-part Facility Evaluation process and public report to determine whether the facility has any CCR management units containing one ton or more of CCR. This requires evaluations at Cross, Winyah, Jefferies, and Grainger Generating Stations. CCR management units containing 1,000 tons or more of CCR must then comply with groundwater monitoring, corrective action, closure, and post-closure care requirements. The Facility Evaluation Report Part 1 is currently under development to identify CCR management units, although the Winyah Generating Station West Ash Pond and Jefferies Generating Station Rail Loop area are already known CCR management units. Subsequent to June 25, 2025, the Authority estimated a potential impact of approximately $34.6 million related to remediation of the Jefferies Generating Station Rail Loop area. This rulemaking also established an additional closure option for units that are closing by removal of CCR but cannot complete groundwater corrective action within the prescribed closure timeframes. On February 6, 2026, EPA announced a final rule providing facilities additional time to meet some of the CCRMU requirements.

Another rulemaking is expected in the future. The EPA has proposed a Federal CCR Permit Program, which will set forth procedures to obtain federal CCR permits that would then supersede the existing federal regulations and the self-implementing scheme once a federal permit is issued for a regulated facility. This federal program will apply to facilities in states that do not have an approved CCR program, which currently includes South Carolina, although the EPA is encouraging states to develop and implement their own CCR programs.

The CCR regulations and the EPA's interpretation of them have changed frequently, and the recent and upcoming changes in the rules and their interpretations have been and will likely continue to be litigated. Additionally, the EPA has utilized its enforcement authority and found many instances of non-compliance at other utilities according to these changes in interpretations. The Authority cannot predict interpretive changes from the EPA, additional regulatory changes that the EPA may propose, or the impacts of such proposals upon the Authority's operations and financial results until they are proposed and finalized and their impacts upon the Authority can be evaluated.

Pond Closures. The Authority has ash and gypsum slurry ponds at the Grainger, Winyah, Cross, and Jefferies Generating Stations. Five ponds (Winyah Slurry Pond 2, Winyah South Ash Pond, Grainger Ash Pond 1, Grainger Ash Pond 2, and the Cross Gypsum Pond) have already completed closure in accordance with SCDES's requirements. Closure plans for the Jefferies Generating Station ash pond and decant pond (a non-CCR unit) and for the Winyah West Ash Pond have been approved by SCDES and closure is in progress, with regulatory deadlines of 2030, and all except the Jefferies decant pond are subject to the requirements of the Legacy CCR Rule that went into effect on November 8, 2024. The Cross Bottom Ash Pond and the remaining ponds at the Winyah Generating Station, including the Winyah South Ash Pond, are subject to both the CCR Rule's closure requirements and to SCDES closure regulations. Closure of the Winyah South Ash Pond is complete and is in progress on the remaining ponds, and SCDES plans are being developed and implemented to facilitate closure by the CCR Rule's regulatory deadlines 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. Closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards for those units at Cross and Winyah that are subject to groundwater corrective action. Pond closure activities are expected to continue at least through 2031, and estimates of remaining costs are projected to be approximately $260.6 million between 2026 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 also do not include potential expenses associated with the Legacy Rule's requirements for CCR Management Units ("CCRMUs") that have not yet been identified.

Beneficial Use of Coal Combustion Products. Coal combustion residuals that can be beneficially reused are considered coal combustion products ("CCP"), and include fly ash, bottom ash, and flue gas desulfurization products such as gypsum. The Authority has entered into contracts for the beneficial use of CCPs and continually looks for new markets for excess quantities. The Authority provides synthetic gypsum to American Gypsum for its wallboard production requirements. Gypsum is also marketed to cement companies and used in the agriculture industry. Additionally, dry fly ash from the operating units and ash reclaimed from the Authority's ash ponds are used in the cement industry, and bottom ash is used by concrete block manufacturers to produce concrete block.

Industrial Solid Waste Landfills. At Cross and Winyah Generating Station, dry CCRs which are not beneficially used are disposed of in on-site industrial Class 3 solid waste landfills. These landfills are permitted by SCDES to receive the Authority's CCR waste from any Authority coal-fired generating units and ash ponds. 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 SCDES in December 2022. The Cross Generating Station's Class 3 landfill continues in operation. These two operational Class 3 landfills are also subject to the CCR Rule. These landfills were located, designed, and constructed to meet CCR requirements for continued operation. Additional landfill cells for the Cross and Winyah Class 3 landfills are already fully permitted and will be constructed as the existing cells are filled and closed to provide ongoing landfill capacity.

Pollution Remediation Obligations

A 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 an underground storage tank ("UST") had been removed, an aboveground storage tank ("AST") with dispensers was present, and subsurface hydrocarbon contamination was present (both in soil and groundwater). Based on the assessment findings, SCDES began working with the lessee to address the contamination at the site, identified as Site ID #-01935. SCDES was not successful in addressing the contamination with the lessee and contacted the Authority as the owner of the property. On February 26, 2014, the Authority was notified by SCDES 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 SCDES approved work plans. On March 17, 2021, SCDES issued a directive to Packs Landing Marina for a Site-Specific Work Plan to conduct additional testing due to creosote found at the site. The Authority then entered into a Responsible Party Voluntary Cleanup Contract ("VCC") with SCDES on March 18, 2022. The VCC addresses the Authority and SCDES's cooperative plan for remediation of the creosote on the property. The Authority submitted its Remedial Work Plan pursuant to the VCC process in July 2022, and SCDES approved it in August 2022. In June 2023, the first Remedial Assessment Report, which indicated shallow impacted soils that could be excavated, was submitted to SCDES and approved in July 2024. While awaiting SCDES approval, however, alternatives were evaluated to determine if another remediation approach would be more appropriate under the circumstances. This evaluation and additional discussions with SCDES led to the determination that the most beneficial and cost-effective plan was to reclassify the site from residential to industrial usage, cap impacted soils, relocate the on-site water supply well, and monitor groundwater. This updated Remedial Work Plan was approved by SCDES on August 14, 2025, and is currently being implemented. The hydrocarbon contamination is not addressed in the creosote VCC or Remedial Work Plan since Monitored Natural Attenuation ("MNA") is the approved remedial action for that contamination. Groundwater and surface water at the site is being sampled and reported on a quarterly basis until site-specific target levels are reached.

The former Grainger Generating Station property was transferred to the City of Conway in July 2025, and Santee Cooper is a responsible party for contamination associated with activities prior to the transfer. The City of Conway plans to redevelop the site and entered into a VCC with SCDES in 2025. Assessments associated with this VCC and the CCR Legacy Rule requirements are ongoing and may result in additional soil and groundwater remediation work at the site, although the extent of these potential impacts have not yet been determined.

No additional pollution remediation liabilities were recorded for the years 2025 and 2024.

FERC Hydro Licensing

The Authority operates the Santee Cooper Project (FERC P-199), which includes its Jefferies Hydro Station and certain other property such as 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. Various studies intended to inform future management of diadromous fish species at the project, including the endangered shortnose sturgeon and Atlantic sturgeon, were initiated in 2024 in close coordination with the South Carolina Department of Natural Resources, United States Fish & Wildlife Service, National Marine Fisheries Service, and the United States Army Corps of Engineers. 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 \$3.8 million in capital assets for the FERC Hydroelectric license through December 31, 2025.

NERC Regulation

NERC establishes and enforces reliability standards which include operating and planning standards as well as critical infrastructure protection standards for the Bulk Electric System. Compliance with these standards is mandatory. Though the Authority has not received any major fines, the current maximum penalty that may be levied for violating a NERC Reliability Standard is \$1,544,521 per violation, per day. The Authority has formal programs, processes, and policies in place to promote compliance with these standards, including a NERC Compliance and Coordination Unit. However, it is not possible to predict whether the Authority will have future violations or what the fines for such violations might be.

Nuclear Matters

Summer Nuclear Unit 1 is subject to regulation by the NRC. Dominion and the Authority were required to obtain liability insurance and a United States Government indemnity agreement for Summer Nuclear Unit 1 in order for the NRC operating license to be issued. This primary insurance and the retrospective assessments are to insure against the maximum liability under the federal Price-Anderson Act for any public claims arising from a nuclear incident. The Further Consolidated Appropriations Act of 2024 extends the Price-Anderson Act until 2065.

The NRC requires that a licensee of a nuclear reactor provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable NRC regulations, the Authority established an external trust to comply with the NRC regulations and began making deposits into the external decommissioning fund in September 1990.

In addition to providing for the minimum requirements imposed by the NRC, the Authority established, in 1983, an internal decommissioning fund. Based on the most recent decommissioning cost estimates developed by Dominion, assuming a SAFSTOR (delayed decommissioning) scenario that includes operating the plant until 2062 (80-year plant life), both the internal and external funds, which had a combined market value of approximately $218 million on December 31, 2024, along with future deposits, investment earnings, and credits from DOE reimbursements for spent fuel storage costs, are estimated to provide sufficient funds for the Authority's one-third share of the total estimated decommissioning cost (approximately $415 million in 2024 dollars).

Inflation Reduction Act and OBBBA

In August 2022, Congress adopted the Inflation Reduction Act ("IRA"), which included several changes beneficial to public power entities. For example, the IRA included provisions enabling public power entities to receive direct payment tax credits that previously they could not utilize because of their tax status. Direct pay tax credits provide for payments to be made directly to the public entity by the U.S. Treasury, subject to a 15 percent reduction for projects that utilize tax-exempt financing.

In July 2025, Congress adopted P.L. 119-21, known as the "One Big, Beautiful Bill Act" (the "OBBBA"). Although the OBBBA does not rescind the specific direct payment provisions beneficial to public power entities, it amends many of the underlying tax credit provisions that might be used by state or local governments as the basis for claiming a direct payment and adds new requirements that limit the ability of state and local governments to take advantage of the direct pay program. Most notably, OBBBA requires solar and wind projects to begin construction within 12 months of the OBBBA's enactment and be placed into service before 2028. For other renewable and battery energy storage system projects, the OBBBA alters the "applicable year" for purposes of the phase-out of tax credits to fix the applicable year at 2032 rather than having it dependent on the extent of U.S. electricity sector greenhouse gas emissions, with the effect that the phase-out of the tax credits for qualified facilities will effectively start for facilities that begin construction in 2034. The OBBBA also eliminates tax credits for projects constructed with material assistance from a prohibited foreign entity.

The impact of these changes on the Authority's resource planning is that solar and wind are projected to be less cost-effective options relative to other resource options. However, recognizing that these resources provide benefits of fuel diversity, reduced carbon risk, and improved environmental emissions, Santee Cooper intends to continue to regularly assess the market for renewable resources.

Legislative Matters

In 2025, South Carolina's Governor and the South Carolina General Assembly were focused on policy that promoted new energy infrastructure for South Carolina. This focus included support for the Authority to pursue a new natural gas combined cycle project in South Carolina with Dominion in Colleton County at a retired coal generation facility.

Act 41 of 2025 ("Act 41"), referred to as the "Energy Security Act," was passed by the General Assembly and signed into law by the Governor on May 12, 2025. Act 41 authorizes the Authority to jointly own a natural gas combined cycle project with Dominion and also encourages the Authority and Dominion to pursue the project. Act 41 also made changes to the regulatory and permitting structure in South Carolina to promote more timeliness and certainty in the regulatory and permitting processes in South Carolina. The Authority's President and Chief

Executive Officer and staff participated in numerous hearings and policy discussions surrounding the Energy Security Act.

In 2026, the Authority expects the South Carolina General Assembly will conduct elections for four of the seven seats on the SCPSC, and the South Carolina Senate is expected to consider appointments by the South Carolina Governor to the Authority's board. Under Act 90 of 2021, the twelve Authority board seats have four-year terms, and three seats expire each year. Current board members continue to serve until their successors are confirmed. See "THE AUTHORITY – Governance" herein.

The Authority expects energy policy discussions and debate to take place during the 2026 legislative session, which may include issues such as market optionality for large users, the environmental and cost impacts of data centers, energy efficiency, and energy affordability. The South Carolina General Assembly's regular legislative session runs from January 13 to May 14, 2026.

INVESTMENT CONSIDERATIONS

The following is a discussion of certain risks that could affect payments to be made with respect to the 2026 Bonds. Such discussion is not exhaustive, should be read in conjunction with all other parts of this Official Statement and should not be considered a complete description of all risks that could affect payments with respect to the 2026 Bonds. Prospective purchasers of the 2026 Bonds should analyze carefully the information contained in this Official Statement, including the Appendices attached hereto.

Environmental Regulation

The Authority and other electric utilities are subject to extensive and continuing federal, state, and local environmental regulations and requirements affecting, among other things, construction and operation of new facilities, upgrades to existing facilities, and retirement or restrictions on operations, as well as air pollutant emissions, wastewater discharges, and the management of hazardous and solid wastes. Federal, state, and local laws, regulations, standards, and procedures which regulate the environmental impact of electric utilities are subject to change. These changes may arise from continuing legislative, regulatory, and judicial action regarding such standards and procedures as well as changes in presidential administrations that can impact legal and regulatory interpretations and enforcement priorities. Consequently, there is no assurance that the Authority's facilities will remain subject to the regulations currently in effect, will always be in compliance with regulations, or will always be able to obtain all required operating permits. Changes in these requirements or the inability to comply with existing environmental standards could result in substantial additional capital expenditures to achieve or maintain compliance or could result in reduced operating levels or the complete shutdown of individual electric generating units, which could have an adverse impact on the Authority's Revenues.

Certain environmental laws can impose the entire cost or a portion of the cost of investigating and cleaning up a site contaminated with hazardous substances, regardless of fault, upon any one or more responsible parties, including the current or previous owners or operators of the site. Such environmental laws can also impose liability on any person who arranges for the disposal or treatment of hazardous substances at a contaminated site. Some of the sites that the Authority currently or historically has owned or operated potentially could require investigation or remediation under such environmental laws which could result in material costs for the Authority.

In 2025, South Carolina legislators passed Act 41 which streamlines environmental permitting by requiring agencies to expedite reviews, coordinate more effectively, and provide constructive assistance to applicants. This reduces delays for energy infrastructure projects while maintaining compliance with environmental standards, giving developers greater predictability, and supporting the state's economic and energy growth.

Bankruptcy; Enforceability of Remedies and Certain Legal Opinions

The enforceability of the rights and remedies of the Holders, the obligations of the customers of the Authority (and of the Authority itself), and the lien and pledge created by the Revenue Obligation Resolution are subject to the United States Bankruptcy Code (the "Bankruptcy Code") and/or to other applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws relating to or affecting the enforcement of creditors' rights generally, to equitable principles that may limit the enforcement under South Carolina law of certain remedies, and to exercise by the United States of America of powers delegated to it by the United States Constitution.

Some of the risks associated with a bankruptcy, insolvency, or dissolution include the risks of delay in payment and of nonpayment. There may be other possible effects of a bankruptcy of the Authority that could result in delays or reductions in payments on the 2026 Bonds or result in losses to Holders. Regardless of any specific adverse determinations in any such bankruptcy proceeding, the fact of the pendency of such a bankruptcy proceeding could have an adverse effect on the liquidity and value of the 2026 Bonds. Potential purchasers of the 2026 Bonds should consult their own attorneys and advisors in assessing the risk and the likelihood of recovery in the event the Authority or any other party becomes a debtor in a bankruptcy, insolvency, or dissolution case prior to the time Holders are paid in full.

The remedies available to the holders of the 2026 Bonds upon an event of default under the Revenue Obligation Resolution are in many respects dependent upon regulatory and judicial actions that are in many instances subject to discretion and delay. Under existing laws and judicial decisions, the remedies provided for in the Revenue Obligation Resolution may not be readily available or may be limited. Legal opinions to be delivered concurrently with the delivery of the 2026 Bonds will be qualified to the extent that the enforceability of certain legal rights related to the 2026 Bonds is subject to limitations imposed by bankruptcy, reorganization, insolvency, or other similar laws affecting the enforcement of creditors' rights generally and by equitable remedies and proceedings generally and to limitations on legal remedies against agencies of the State.

Chapter 9 of the Bankruptcy Code contains provisions relating to the adjustment of debts of a state's political subdivisions, public agencies, and instrumentalities (each an "eligible entity"). Pursuant to the Bankruptcy Code, political subdivisions, public agencies, and instrumentalities of a State must be specifically authorized under state law to file a petition under Chapter 9. States are free to pass, and amend, legislation granting or denying such entities the authority to file a petition under the Bankruptcy Code. Under the Bankruptcy Code and in certain circumstances described therein, an eligible entity may be authorized to initiate Chapter 9 proceedings without prior notice to or consent of its creditors, which proceedings may result in a material and adverse modification or alteration of the rights of its secured and unsecured creditors, including holders of its bonds and notes. South Carolina law allows municipalities, including the Authority, the right to file for Chapter 9 protections on their own.

The enforceability of the various legal agreements of the Authority may be limited by bankruptcy, reorganization, insolvency, moratorium, or other similar laws affecting the rights of creditors or secured parties generally and by the exercise of judicial discretion in accordance with general principles of equity. Certain agreements with the Authority's customers are executory contracts. If any of the parties with which the Authority has contracted under such agreements is involved in a bankruptcy proceeding, the relevant agreement could be discharged in return for a claim for damages against the party's estate with uncertain value. In such an event, the Revenues could be materially and adversely affected. Similarly, in the event that the Authority is involved in a bankruptcy proceeding, exercise of the remedies afforded under the Revenue Obligation Resolution may be stayed.

Effects of Weather and Other Catastrophic Events

Weather conditions can affect a utility's operations and financial results. For example, in the past the Authority has delivered less electricity when weather conditions have been milder than normal and, as a consequence, earned less income from those operations. Mild weather in the future could diminish the revenues and results of operations and harm the financial condition of the Authority. Fluctuations in weather conditions could result in higher bills for customers and higher write-offs of receivables, as well as a greater number of disconnections for non-payment. Severe weather can be destructive for the Authority, causing outages and property damage, adversely affecting operating expenses and revenues.

In addition, the occurrence of one or more natural disasters, such as hurricanes, tropical storms, floods, wildfires, earthquakes, major or extended weather storms, droughts, extreme heat, or other sudden or severe changes in climate conditions, or man-made mishaps (such as a coal ash pond failure or natural gas pipeline failure), could adversely affect the Authority's operations and financial performance in a number of ways. For example, such events could: (i) cause outages, fluctuations in customer energy needs, and physical property damage, human injury or loss of life from energized equipment, hazardous substances, or explosions, fires, leaks, or other events, especially where the Authority's facilities are located near populated areas; (ii) cause breakdown or failure, including explosions, fires, leaks, or other major events, of the Authority's equipment, transmission, or distribution systems or pipelines and impede the Authority's ability to generate, transmit, and/or distribute power; (iii) adversely affect the Authority's key contractors or suppliers; or (iv) result in disadvantageous changes to federal, state, or local policies, laws and regulations.

The risk of wildfires is addressed primarily through asset management programs for natural gas transmission and distribution operations, and through vegetation management programs for electric transmission and distribution facilities. If it is found to be responsible for such a fire, the Authority could suffer costs, losses, and damages, all or some of which may not be recoverable through insurance, legal, regulatory cost recovery, or other processes. If not recovered through these means, the costs, losses, and damages could materially affect the Authority's business and financial results including its reputation with customers, regulators, governments, and financial markets. Resulting costs could include fire suppression costs, regeneration, timber value, increased insurance costs, and costs arising from damages and losses incurred by third parties.

The Authority's operations may be adversely affected, directly or indirectly, by acts of sabotage, wars, or terrorist incidents, including cyber-attacks (including cyber-attacks impacting the Authority's technology systems, network infrastructure, and integrated transmission system), and by catastrophic events such as pandemic health events (including, without limitation, the COVID-19 outbreak), or other similar occurrences.

Cybersecurity and other Safety and Security Risks

The Authority relies on a large and complex technology environment to conduct its operations and faces multiple cybersecurity threats including, but not limited to, hacking, viruses, malware, and other attacks on its computing and other digital networks and systems. Cybersecurity incidents could result from unintentional events or from deliberate attacks by unauthorized entities or individuals attempting to gain access to the Authority's networks and systems for the purposes of misappropriating assets or information or causing operational disruption and damage. Cybersecurity breaches could result in damage to the Authority's information and security systems and networks and cause material disruption to its operations. While the Authority has security measures and other safeguards in place, there can be no assurance that any existing or additional safety and security measures will prove adequate in the event that attacks, including cyber terrorism, are directed at the Authority's systems.

Tax Legislation

Bills have been and in the future may be introduced that could impact the issuance of tax-exempt bonds for transmission and generation facilities. The Authority is unable to predict whether any of these bills or any similar federal bills proposed in the future will become law or, if they become law, what their final form or effect would be. Such an effect, however, could be material to the Authority.

Tariffs and Trade Restrictions

There is currently significant uncertainty about the future relationship between the United States and various other countries with respect to trade policies and tariffs. Tariffs or trade restrictions that may be implemented by the United States or retaliatory trade measures or tariffs implemented by other countries could result in reduced economic activity, increased costs in operating the Authority's business, reduced demand, and changes in purchasing behaviors for the Authority's customers. In the ordinary course of business, the Authority procures some materials and equipment globally. While tariffs and other retaliatory trade measures imposed by other countries on the United States have not yet had a significant impact on the Authority's business, the Authority cannot predict future developments and its impact on operations.

The Electric Utility Industry Generally

The electric utility industry in general has been affected by regulatory changes, market developments, and other factors which have impacted, and will probably continue to impact, the financial condition, and competitiveness of electric utilities and the level of utilization of facilities, such as those of the Authority. Such factors include, among others, (a) effects of compliance with rapidly changing environmental, safety, licensing, regulatory, and legislative requirements, (b) changes resulting from conservation and demand-side management programs on the timing and use of electric energy, (c) changes that might result from national energy policies, (d) effects of competition from other electric utilities (including increased competition resulting from mergers, acquisitions, and strategic alliances of competing electric (and gas) utilities and from competitors transmitting less expensive electricity from much greater distances over an interconnected system), and new methods of producing low cost electricity, (e) increased competition from independent power producers, marketers, and brokers, (f) self-generation by certain industrial, commercial, and residential customers, (g) issues relating to the ability to issue tax-exempt obligations, (h) restrictions on the ability to sell to nongovernmental entities electricity from projects financed with outstanding tax-exempt obligations, (i) changes from projected future load requirements, (j) increases in costs, (k) shifts in the availability and relative costs of different fuels, and (l) changes in customer preferences for sustainable operations and utilization of alternative energy sources.

Concentration of revenues from a single external customer increases credit and market concentration risks for a utility like the Authority. The loss of, or significant reduction in business from, major customers could have a material adverse effect on the Authority's financial condition including liquidity and operating results. The Authority routinely assesses its customer relationships, including creditworthiness, market conditions, and competitive pressures, to mitigate risks associated with customer concentration.

While the Authority makes every effort to anticipate and predict what effect the above factors may have on its business operations and financial condition, any of these factors as well as other unforeseen economic, market, and regulatory changes can occur. In addition, the Authority recognizes the uncertainty that a change in policies that a new presidential administration can produce and is unable to predict the likelihood of any regulatory changes, any legal challenges to such changes or the effects any such changes may have on the Authority's business operations or financial condition, but the effects could be significant.

Extensive information on the electric utility industry is available from sources in the public domain, and potential purchasers of the 2026 Bonds should obtain and review such information.

Effects on the Authority

The foregoing is a brief discussion of certain factors affecting the electric utility industry and the Authority. This discussion does not purport to be comprehensive or definitive, and these matters are subject to change subsequent to the date hereof. Extensive information on the electric utility industry is, and will be, available from legislative and regulatory bodies and other sources in the public domain, and potential purchasers of the Bonds should obtain and review such information.

LITIGATION

General

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 other than those described below. The Authority is involved in numerous actions arising from the ordinary course of its business and is defending pending claims, including the actions described below. Claims may be settled or decided by a judge, jury, or arbitrator. The Authority is unable to predict the outcome of the pending matters described below or predict additional claims which may arise. 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, including the 2026 Bonds.

Pending Matters or Disputes

Central Litigation: L-Rate Arbitration. Based on a provision of the Coordination Agreement, Central asked to provide service to one of its member's large load customers using the Authority's L-rate, which under the circumstances would result in shifting costs to retail customers. The Authority requested Central work together to reach a resolution, as required by the Coordination Agreement. Central refused and submitted a notice of arbitration pursuant to the Coordination Agreement. Both parties selected their arbitrators, and those arbitrators selected the third arbitrator (Chair). The parties are conducting discovery, and the arbitration hearing is scheduled to commence after May 18, 2026.

South Carolina Public Service Authority v. U.S. Army Corps of Engineers. The Authority filed a claim on October 2, 2015, against the U.S. Army Corps of Engineers ("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 and that the COE owes the Authority approximately $5.3 million in contract payments for 2015. 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 credit and a credit in the amount of $716,874 was due to the COE for 2015. 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 Board denied the Authority's appeals and remanded to the parties for "negotiation for the value of the additional capacity for the final 20 years of the contract performance period based on the contract." An agreement in principle was reached on July 26, 2024, and final terms are under discussion.

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TAX MATTERS

Tax Matters Relating to the 2026A Bonds and the 2026C Bonds

Opinion of Bond Counsel

In the opinion of Bond Counsel, under existing law and assuming continuing compliance with certain tax covenants, representations and certifications made by the Authority described herein, (i) interest on the 2026A Bonds and 2026C Bonds (collectively, the "Tax-Exempt Bonds") is excluded from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"), and (ii) interest on the Tax-Exempt Bonds is not a specific preference item for purposes of the federal alternative minimum tax imposed on individuals and corporations under the Code; however, for tax years beginning after December 31, 2022, interest on the Tax-Exempt Bonds is taken into account in determining the "adjusted financial statement income" of certain corporations that are subject to the alternative minimum tax imposed under Section 55 of the Code.

In addition, in the opinion of Bond Counsel, under existing law, interest on the Tax-Exempt Bonds is exempt from all taxation by the State, its counties, municipalities, and school districts except estate, transfer, or certain franchise taxes. Interest paid on the Tax-Exempt Bonds is currently subject to the tax imposed on banks by Section 12-11-20, Code of Laws of South Carolina 1976, as amended, which is enforced by the South Carolina Department of Revenue as a franchise tax.

Certain Ongoing Federal Tax Requirements and Covenants

The Code imposes certain requirements that must be met subsequent to the issuance and delivery of the Tax-Exempt Bonds for interest thereon to be and remain excluded from gross income for federal income tax purposes pursuant to Section 103 of the Code. These requirements include, but are not limited to, requirements relating to the use and expenditure of gross proceeds of the Tax-Exempt Bonds, yield and other restrictions on investments of gross proceeds, and the arbitrage rebate requirement that requires certain excess earnings on gross proceeds to be rebated to the federal government. Noncompliance with such requirements could cause the interest on the Tax-Exempt Bonds to be included in gross income for federal income tax purposes retroactive to the date of issue of the Tax-Exempt Bonds. The Authority, pursuant to the Revenue Obligation Resolution and the Tax Certificate has covenanted to comply with the applicable requirements of the Code in order to maintain the exclusion of the interest on the Tax-Exempt Bonds from gross income for federal income tax purposes pursuant to Section 103 of the Code. In addition, the Authority has made certain representations and certifications in the Revenue Obligation Resolution and the Tax Certificate on which Bond Counsel will rely. Bond Counsel will not independently verify the accuracy of those representations and certifications.

Ancillary Tax Matters

Although Bond Counsel is of the opinion that interest on the Tax-Exempt Bonds is excluded from gross income for federal income tax purposes, the ownership or disposition of, or the accrual or receipt of amounts treated as interest on, the Tax-Exempt Bonds may otherwise affect a holder's federal, state, local, foreign or other tax liability. The nature and extent of these other tax consequences depends upon the particular tax status of the holder or the holder's other items of income or deduction. Prospective owners, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the tax consequences of owning and disposing of the Tax-Exempt Bonds. Bond Counsel expresses no opinion regarding any such other tax consequences.

Original Issue Discount

To the extent the issue price of any maturity of the Tax-Exempt Bonds is less than the amount to be paid at maturity of such Tax-Exempt Bonds (excluding amounts stated to be interest and payable at least annually over the term of such Tax-Exempt Bonds), the difference constitutes "original issue discount," the accrual of which, to the extent properly allocable to each beneficial owner thereof, is treated as interest on the Tax-Exempt Bonds which is excluded from gross income for federal income tax purposes. For this purpose, the issue price of a particular maturity of the Tax-Exempt Bonds is the first price at which a substantial amount of such maturity of the Tax-Exempt Bonds is sold to the public (excluding bond houses, brokers, or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers). Any prices set forth on the inside cover page of the Official Statement may or may not reflect the prices at which a substantial amount of the Tax-Exempt Bonds were ultimately sold to the public.

In general, the original issue discount with respect to any maturity of the Tax-Exempt Bonds accrues daily over the term to maturity of such Tax-Exempt Bonds on the basis of a constant interest rate compounded semiannually (with straight-line interpolations between compounding dates). The accruing original issue discount is added to the adjusted basis of such Tax-Exempt Bonds to determine taxable gain or loss upon disposition (including sale, redemption, or payment on maturity) of such Tax-Exempt Bonds. Accrued original issue discount may be taken into account as an increase in the amount of tax-exempt income received or deemed to have been received for purposes of determining various other tax consequences of owning a Tax-Exempt Bond even though there will not be a corresponding cash payment. Holders of Tax-Exempt Bonds having original issue discount, and especially any holder who is not an original owner of such a bond who bought the bond at its initial public offering price, should consult their tax advisors with respect to the tax consequences of acquiring, holding, and disposing of Tax-Exempt Bonds with original issue discount.

Original Issue Premium

Tax-Exempt Bonds purchased, whether at original issue or otherwise, for an amount higher than their principal amount payable at maturity (or, in some cases, at their earlier call date) ("Premium Bonds") will be treated as having amortizable bond premium. No deduction is allowable for the amortizable bond premium in the case of bonds, like Premium Bonds, the interest on which is excluded from gross income for federal income tax purposes. However, the amount of tax-exempt interest received, and a holder's basis in a Premium Bond, will be reduced by the amount of amortizable bond premium properly allocable to such holder. As a consequence of reducing a holder's basis in a Premium Bond, under certain circumstances a holder of a Tax-Exempt Bond acquired with original issue premium may realize a taxable gain upon disposition thereof even though it is sold or redeemed for an amount equal to or less than such holder's original cost of acquiring the bond. Holders of any Premium Bonds should consult their own tax advisors with respect to the proper treatment of amortizable bond premium with respect to the tax consequences of acquiring, holding, and disposing of Premium Bonds.

Changes in Law and Post Issuance Events

The opinions of Bond Counsel are based on current legal authority, cover certain matters not directly addressed by such authorities, and represent Bond Counsel's judgment as to the proper treatment of the Tax-Exempt Bonds for federal income tax purposes. Such opinions are not binding on the Internal Revenue Service (the "IRS") or the courts. Furthermore, legislative or administrative actions and court decisions, at either the federal or state level, could have an adverse impact on the potential benefits of the exclusion from gross income of the interest on the Tax-Exempt Bonds for federal or state income tax purposes and thus on the value or marketability of the Tax-Exempt Bonds. This could result from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), repeal of the exclusion of the interest on the Tax-Exempt Bonds from gross income for federal or state income tax purposes, or otherwise. It is not possible to predict whether any legislative or administrative actions or court decisions having an adverse impact on the federal or state income tax treatment of holders of the Tax-Exempt Bonds may occur. Prospective purchasers of the Tax-Exempt Bonds should consult their own tax advisors regarding the impact of any change in law on the Tax-Exempt Bonds.

Bond Counsel has not undertaken to advise in the future whether any events after the date of issuance and delivery of the Tax-Exempt Bonds may affect the tax status of interest on the Tax-Exempt Bonds. Bond Counsel expresses no opinion as to any federal, state or local tax law consequences with respect to the Tax-Exempt Bonds, or the interest thereon, if any action is taken with respect to the Tax-Exempt Bonds or the proceeds thereof upon the advice or approval of other counsel.

IRS Examination

Bond Counsel's engagement with respect to the Tax-Exempt Bonds ends with the issuance of the Tax-Exempt Bonds, and unless separately engaged, Bond Counsel is not obligated to defend the Authority regarding the tax-exempt status of the Tax-Exempt Bonds in the event of an audit examination by the IRS. Under current procedures, parties other than the Authority and its appointed counsel, including the beneficial owners, would have little, if any, right to participate in the audit examination process. Moreover, because achieving judicial review in connection with an audit examination of tax-exempt bonds is difficult, obtaining an independent review of IRS positions with which the Authority legitimately disagrees may not be practicable. Any action of the IRS, including but not limited to, selection of the Tax-Exempt Bonds for audit, or the course or result of such audit, or an audit of bonds presenting similar tax issues may affect the market price for, or the marketability of, the Tax-Exempt Bonds, and may cause the Authority or the beneficial owners to incur significant expense.

Information Reporting and Backup Withholding

Interest on federally tax-exempt obligations such as the Tax-Exempt Bonds is subject to information reporting in a manner similar to interest paid on taxable obligations. Backup withholding may be imposed on payments to any holder of the Tax-Exempt Bonds who fails to provide certain required information and who is not an exempt person. The reporting requirement does not in and of itself affect or alter the excludability of interest on the Tax-Exempt Bonds from gross income for federal income tax purposes or any other federal tax consequence of purchasing, holding or selling federally tax-exempt obligations.

Tax Matters Relating to the 2026B Bonds

Opinion of Bond Counsel

In the opinion of Bond Counsel, under existing law, interest on the 2026B Bonds (the "Taxable Bonds") is exempt from all taxation by the State, its counties, municipalities, and school districts except estate, transfer, or certain franchise taxes. Interest paid on the Taxable Bonds is currently subject to the tax imposed on banks by Section 12-11-20, Code of Laws of South Carolina 1976, as amended, which is enforced by the South Carolina Department of Revenue as a franchise tax.

Certain United States Federal Income Tax Matters

The following is a summary of certain anticipated United States federal income tax consequences of the purchase, ownership and disposition of the Taxable Bonds. The summary is based upon the provisions of the Code, the Treasury Regulations promulgated thereunder and the judicial and administrative rulings and decisions now in effect, all of which are subject to change. Such authorities may be repealed, revoked, or modified, possibly with retroactive effect, so as to result in United States federal income tax consequences different from those described below. The summary generally addresses Taxable Bonds held as capital assets within the meaning of Section 1221 of the Code and does not purport to address all aspects of federal income taxation that may affect particular investors in light of their individual circumstances or certain types of investors subject to special treatment under the federal income tax laws, including, but not limited to, financial institutions, insurance companies, dealers and traders in securities or currencies, persons holding such Taxable Bonds as a hedge against currency risks or as a position in a "straddle," "hedge," "constructive sale transaction" or "conversion transaction" for tax purposes, certain taxpayers that are required to prepare certified financial statements or file financial statements with certain regulatory or governmental agencies, certain United States expatriates, REITs, RICs, partnerships, S corporations, trusts, estates, tax exempt organizations or persons whose functional currency is not the United States dollar. In addition, this summary does not address (i) alternative minimum tax issues, (ii) the net investment income tax imposed (3.8% surtax) under Section 1411 of the Code, (iii) the indirect effects on person who hold equity interests in a holder, or (iv) holders other than original purchasers that acquire Taxable Bonds pursuant to this offering at their initial issue price except where otherwise specifically noted. Potential purchasers of the Taxable Bonds should consult their own tax advisors in determining the federal, state, local, foreign and other tax consequences to them of the purchase, holding and disposition of the Taxable Bonds.

The Authority has not sought and will not seek any rulings from the IRS with respect to any matter discussed herein. No assurance can be given that the IRS would not assert, or that a court would not sustain, a position contrary to any of the tax characterizations and tax consequences set forth below.

U.S. Holders

As used herein, the term "U.S. Holder" means a beneficial owner of Taxable Bonds that is (a) an individual citizen or resident of the United States for federal income tax purposes, (b) a corporation, including an entity treated as a corporation for federal income tax purposes, created or organized in or under the laws of the United States or any State thereof (including the District of Columbia), (c) an estate whose income is subject to federal income taxation regardless of its source, or (d) a trust if a court within the United States can exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust. Notwithstanding clause (d) of the preceding sentence, to the extent provided in Treasury Regulations, certain trusts in existence on August 20, 1996, and treated as United States persons prior to that date that elect to continue to be treated as United States persons also will be U.S. Holders. In addition, if a partnership (or other entity or arrangement treated as a partnership for federal income tax purposes) holds Taxable Bonds, the tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partnership. If a U.S. Holder is a partner in a partnership (or other entity or arrangement treated as a partnership for federal income tax purposes) that holds Taxable Bonds, the U.S. Holder is urged to consult its own tax advisor regarding the specific tax consequences of the purchase, ownership and dispositions of the Taxable Bonds.

Taxation of Interest Generally

Interest on the Taxable Bonds is not excluded from gross income for federal income tax purposes under Section 103 of the Code and so will be fully subject to federal income taxation. Purchasers will be subject to federal income tax accounting rules affecting the timing and/or characterization of payments received with respect to such Taxable Bonds. Subject to the discussions below addressing original issue discount and bond premium, interest paid on the Taxable Bonds generally will be treated as ordinary interest income at the time such amounts are accrued or received, in accordance with the U.S. Holder's method of accounting for United States federal income tax purposes.

Original Issue Discount

The following summary is a general discussion of certain federal income tax consequences of the purchase, ownership and disposition of Taxable Bonds issued with original issue discount ("Discount Taxable Bonds"). A Taxable Bond generally will be treated as having been issued with an original issue discount if the excess of its "stated redemption price at maturity" (defined below) over its issue price (defined as the initial offering price to the public at which a substantial amount of the Taxable Bonds of the same maturity have first been sold to the public, excluding bond houses and brokers) equals or exceeds one quarter of one percent of such Taxable Bond's stated redemption price at maturity multiplied by the number of complete years to its maturity (or, in the case of an installment obligation, its weighted average maturity).

A Taxable Bond's "stated redemption price at maturity" is the total of all payments provided by the Taxable Bond that are not payments of "qualified stated interest." Generally, the term "qualified stated interest" includes stated interest that is unconditionally payable in cash or property (other than debt instruments of the Authority) at least annually at a single fixed rate or certain floating rates.

In general, the amount of original issue discount includible in income by the initial holder of a Discount Taxable Bond is the sum of the "daily portions" of original issue discount with respect to such Discount Taxable Bond for each day during the taxable year in which such holder held such Taxable Bond. The daily portion of original issue discount on any Discount Taxable Bond is determined by allocating to each day in any "accrual period" a ratable portion of the original issue discount allocable to that accrual period.

An accrual period may be of any length, and may vary in length over the term of a Discount Taxable Bond, provided that each accrual period is not longer than one year and each scheduled payment of principal or interest occurs at the end of an accrual period. The amount of original issue discount allocable to each accrual period is equal to the difference between (i) the product of the Discount Taxable Bond's adjusted issue price at the beginning of such accrual period and its yield to maturity (determined on the basis of compounding at the close of each accrual period and appropriately adjusted to take into account the length of the particular accrual period), and (ii) the amount of any qualified stated interest payments allocable to such accrual period. The "adjusted issue price" of a Discount Taxable Bond at the beginning of any accrual period is the sum of the issue price of the Discount Taxable Bond plus the amount of original issue discount allocable to all prior accrual periods minus the amount of any prior payments on the Discount Taxable Bond that were not qualified stated interest payments. Under these rules, holders generally will have to include in income increasingly greater amounts of original issue discount in successive accrual periods.

Holders utilizing the accrual method of accounting may generally, upon election, include in gross income all interest (including stated interest, acquisition discount, original issue discount, de minimis original issue discount, market discount, de minimis market discount, and unstated interest, as adjusted by any amortizable bond premium or acquisition premium) on a Taxable Bond by using the constant yield method applicable to original issue discount, subject to certain limitations and exceptions.

Bond Premium

A holder of a Taxable Bond who purchases such Taxable Bond at a cost greater than its remaining redemption amount will have amortizable bond premium. If the holder elects to amortize this premium under Section 171 of the Code (which election will apply to all Taxable Bonds held by the holder on the first day of the taxable year to which the election applies and to all Taxable Bonds thereafter acquired by the holder), such a holder must amortize the premium using constant yield principles based on the holder's yield to maturity. Amortizable bond premium is generally treated as an offset to interest income, and a reduction in basis is required for amortizable bond premium that is applied to reduce interest payments. Purchasers of Taxable Bonds who acquire such Taxable Bonds at a premium should consult with their own tax advisors with respect to federal, state and local tax consequences of owning such Taxable Bonds.

Sale or Redemption of Bonds

A bondholder's adjusted tax basis for a Taxable Bond is the price such holder pays for the Taxable Bond plus the amount of original issue discount previously included in income and reduced on account of any payments received on such Taxable Bond other than "qualified stated interest" and any amortized bond premium. Gain or loss recognized on a sale, exchange or redemption of a Taxable Bond, measured by the difference between the amount realized and the bondholder's tax basis as so adjusted, generally will give rise to capital gain or loss if the Taxable Bond is held as a capital asset.

If the terms of a Taxable Bond are materially modified, in certain circumstances, a new debt obligation would be deemed "reissued," or created and exchanged for the prior obligation in a taxable transaction. Among the modifications which may be treated as material are those related to the redemption provisions and, in the case of a nonrecourse obligation, those which involve the substitution of collateral. In addition, the defeasance of a Taxable Bond under the defeasance provisions of the Revenue Obligation Resolution could result in a deemed sale or exchange of such Taxable Bond.

Each potential holder of Taxable Bonds should consult its own tax advisor concerning (i) the treatment of gain or loss on sale, redemption or defeasance of the Taxable Bonds, and (ii) the circumstances in which Taxable Bonds would be deemed reissued and the likely effects, if any, of such reissuance.

Non-U.S. Holders

The following is a general discussion of certain United States federal income tax consequences resulting from the beneficial ownership of Taxable Bonds by a person other than a U.S. Holder, a former United States citizen or resident, or a partnership or entity treated as a partnership for United States federal income tax purposes (a "Non-U.S. Holder").

Subject to the discussion of backup withholding and the Foreign Account Tax Compliance Act ("FATCA"), payments of principal by the Authority or any of its agents (acting in its capacity as agent) to any Non-U.S. Holder will not be subject to federal withholding tax. In the case of payments of interest to any Non-U.S. Holder, however, federal withholding tax will apply unless the Non-U.S. Holder (i) does not own (actually or constructively) 10% or more of the voting equity interests of the Authority, (ii) is not a controlled foreign corporation for United States tax purposes that is related to the Authority (directly or indirectly) through stock ownership, and (iii) is not a bank receiving interest in the manner described in Section 881(c)(3)(A) of the Code. In addition, either (i) the Non-U.S. Holder must certify on the applicable IRS Form W-8 (series) (or successor form) to the Authority, its agents or paying agents or a broker under penalties of perjury that it is not a U.S. person and must provide its name and address, or (ii) a securities clearing organization, bank or other financial institution, that holds customers' securities in the ordinary course of its trade or business and that also holds the Taxable Bonds must certify to the Authority or its agent under penalties of perjury that such statement on the applicable IRS Form W-8 (series) (or successor form) has been received from the Non-U.S. Holder by it or by another financial institution and must furnish the interest payor with a copy.

Interest payments may also be exempt from federal withholding tax depending on the terms of an existing United States federal income tax treaty, if any, in force between the United States and the resident country of the Non-U.S. Holder. The United States has entered into an income tax treaty with a limited number of countries. In addition, the terms of each treaty differ in their treatment of interest and original issue discount payments. Non-U.S. Holders are urged to consult their own tax advisor regarding the specific tax consequences of the receipt of interest payments, including original issue discount. A Non-U.S. Holder that does not qualify for exemption from withholding as described above must provide the Authority or its agent with documentation as to his, her, or its identity to avoid the U.S. backup withholding tax on the amount allocable to a Non-U.S. Holder. The documentation may require that the Non-U.S. Holder provide a U.S. tax identification number.

If a Non-U.S. Holder is engaged in a trade or business in the United States and interest on a Taxable Bond held by such holder is effectively connected with the conduct of such trade or business, the Non-U.S. Holder, although exempt from the withholding tax discussed above (provided that such holder timely furnishes the required certification to claim such exemption), may be subject to United States federal income tax on such interest in the same manner as if it were a U.S. Holder. In addition, if the Non-U.S. Holder is a foreign corporation, it may be subject to a branch profits tax equal to 30% (subject to a reduced rate under an applicable treaty) of its effectively connected earnings and profits for the taxable year, subject to certain adjustments. For purposes of the branch profits tax, interest on a Taxable Bond will be included in the earnings and profits of the holder if the interest is effectively connected with the conduct by the holder of a trade or business in the United States. Such a holder must provide the payor with a properly executed IRS Form W-8ECI (or successor form) to claim an exemption from United States federal withholding tax.

Generally, any capital gain realized on the sale, exchange, retirement or other disposition of a Taxable Bond by a Non-U.S. Holder will not be subject to United States federal income or withholding taxes if (i) the gain is not effectively connected with a United States trade or business of the Non-U.S. Holder, and (ii) in the case of an individual, the Non-U.S. Holder is not present in the United States for 183 days or more in the taxable year of the sale, exchange, retirement or other disposition, and certain other conditions are met.

For newly issued or reissued obligations, such as the Taxable Bonds, FATCA imposes U.S. withholding tax on interest payments, certain "passthru" payments, and gross proceeds of the sale of the Taxable Bonds paid to certain foreign financial institutions (which is broadly defined for this purpose to generally include non-U.S. investment funds) and certain other non-U.S. entities if certain disclosure and due diligence requirements related to U.S. accounts or ownership are not satisfied, unless an exemption applies. An intergovernmental agreement between the United States and an applicable non-U.S. country may modify these requirements. In any event, holders or beneficial owners of the Taxable Bonds shall have no recourse against the Authority, nor will the Authority be obligated to pay any additional amounts to "gross up" payments to such persons, as a result of any withholding or deduction for, or on account of, any present or future taxes, duties, assessments or government charges with respect to payments in respect of the Taxable Bonds. However, it should be noted that, under current guidance, FATCA withholding does not apply to gross proceeds, and will apply to certain "passthru" payment no earlier than the date that is two years after publication of final U.S. Treasury Regulations defining the term "foreign passthru payment."

Non-U.S. Holders should consult their own tax advisors with respect to the possible applicability of federal withholding and other taxes upon income realized in respect of the Taxable Bonds.

Information Reporting and Backup Withholding

For each calendar year in which the Taxable Bonds are outstanding, the Authority, its agents or paying agents or a broker is required to provide the IRS with certain information, including a holder's name, address and taxpayer identification number (either the holder's Social Security number or its employer identification number, as the case may be), the aggregate amount of principal and interest paid to that holder during the calendar year and the amount of tax withheld, if any. This obligation, however, does not apply with respect to certain U.S. Holders, including corporations, tax-exempt organizations, qualified pension and profit sharing trusts, and individual retirement accounts and annuities.

If a U.S. Holder subject to the reporting requirements described above fails to supply its correct taxpayer identification number in the manner required by applicable law or under-reports its tax liability, the Authority, its agents or paying agents or a broker may be required to make "backup" withholding of tax on each payment of interest or principal on the Taxable Bonds. This backup withholding is not an additional tax and may be credited against the U.S. Holder's federal income tax liability, provided that the U.S. Holder furnishes the required information to the IRS.

Under current Treasury Regulations, backup withholding and information reporting will not apply to payments of interest made by the Authority, its agents (in their capacity as such) or paying agents or a broker to a Non-U.S. Holder if such holder has provided the required certification that it is not a U.S. person (as set forth in the second paragraph under "Non-U.S. Holders" above), or has otherwise established an exemption (provided that neither the Authority nor its agent has actual knowledge that the holder is a U.S. person or that the conditions of an exemption are not in fact satisfied).

Payments of the proceeds from the sale of a Taxable Bond to or through a foreign office of a broker generally will not be subject to information reporting or backup withholding. However, information reporting (but not backup withholding) may apply to those payments if the broker is one of the following: (i) a U.S. person; (ii) a controlled foreign corporation for U.S. tax purposes; (iii) a foreign person 50% or more of whose gross income from all sources for the three-year period ending with the close of its taxable year preceding the payment was effectively connected with a United States trade or business; or (iv) a foreign partnership with certain connections to the United States.

Payment of the proceeds from a sale of a Taxable Bond to or through the United States office of a broker is subject to information reporting and backup withholding unless the holder or beneficial owner certifies as to its taxpayer identification number or otherwise establishes an exemption from information reporting and backup withholding.

The preceding United States federal income tax discussion is included for general information only and may not be applicable depending upon a holder's particular situation. Holders should consult their tax advisors with respect to the tax consequences to them of the purchase, ownership and disposition of the Taxable Bonds, including the tax consequences under federal, state, local, foreign and other tax laws and the possible effects of changes in those tax laws.

Changes in Law and Post Issuance Events

The opinions of Bond Counsel are based on current legal authority, cover certain matters not directly addressed by such authorities, and represent Bond Counsel's judgment as to the proper treatment of the Taxable Bonds for federal income tax purposes. Such opinions are not binding on the IRS or the courts. Furthermore, legislative or administrative actions and court decisions, at either the federal or state level, could have an impact on the treatment of interest on the Taxable Bonds for federal or state income tax purposes, and thus on the value or marketability of the Taxable Bonds. This could result from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), or otherwise. It is not possible to predict whether any such legislative or administrative actions or court decisions will occur or have an adverse impact on the federal or state income tax treatment of holders of the Taxable Bonds. Prospective purchasers of the Taxable Bonds should consult their own tax advisors regarding the impact of any change in law or proposed change in law on the Taxable Bonds.

Bond Counsel Opinions

The opinions of Bond Counsel are limited to the laws of the State and federal income tax laws. No opinion is rendered by Bond Counsel concerning the taxation of the Tax-Exempt Bonds, Taxable Bonds or the interest thereon under the laws of any other jurisdiction. The forms of the approving opinions of Bond Counsel are attached to this Official Statement as APPENDIX E – "PROPOSED FORMS OF BOND COUNSEL OPINION." Bond Counsel is not rendering any opinions as to any federal and state tax matters other than those described in the opinions attached as APPENDIX E – "PROPOSED FORMS OF BOND COUNSEL OPINION" to this Official Statement. Prospective investors, particularly those who may be subject to special rules, are advised to consult their own tax advisors regarding the federal tax consequences of owning and disposing of the Tax-Exempt Bonds and Taxable Bonds, as well as any tax consequences arising under the laws of any state, local, foreign or other taxing jurisdiction.

CONSIDERATIONS FOR ERISA AND OTHER U.S. BENEFIT PLAN INVESTORS

The Employee Retirement Income Security Act of 1974, as amended ("ERISA"), imposes certain fiduciary obligations and prohibited transaction restrictions on employee pension and welfare benefit plans subject to Title I of ERISA ("ERISA Plans") and on those persons who are fiduciaries with respect to ERISA Plans. Section 4975 of the Code imposes essentially the same prohibited transaction restrictions on tax-qualified retirement plans described in Section 401(a) and 403(a) of the Code, which are exempt from tax under Section 501(a) of the Code, other than governmental and church plans as defined herein ("Qualified Retirement Plans"), and on Individual Retirement Accounts ("IRAs") described in Section 408(b) of the Code (collectively, "Tax-Favored Plans"). Certain employee benefit plans such as governmental plans (as defined in Section 3(32) of ERISA) ("Governmental Plans"), and, if no election has been made under Section 410(d) of the Code, church plans (as defined in Section 3(33) of ERISA) ("Church Plans"), are not subject to ERISA requirements. Additionally, such Governmental and Church Plans are not subject to the requirements of Section 4975 of the Code but may be subject to applicable federal, state or local law ("Similar Laws") which is, to a material extent, similar to the foregoing provisions of ERISA or the Code. Accordingly, assets of such plans may be invested in the 2026 Bonds without regard to the ERISA and Code considerations described below, subject to the provisions of Similar Laws.

In addition to the imposition of general fiduciary obligations, including those of investment prudence and diversification and the requirement that a plan's investment be made in accordance with the documents governing the plan, Section 406 of ERISA and Section 4975 of the Code prohibit a broad range of transactions involving assets of ERISA Plans and Tax-Favored Plans and entities whose underlying assets include plan assets by reason of ERISA Plans or Tax-Favored Plans investing in such entities (collectively, "Benefit Plans") and persons who have certain specified relationships to the Benefit Plans ("Parties in Interest" or "Disqualified Persons"), unless a statutory or administrative exemption is available. The definitions of "Party in Interest" and "Disqualified Person" are expansive. While other entities may be encompassed by these definitions, they include, most notably: (i) fiduciary with respect to a plan; (ii) a person providing services to a plan; (iii) an employer or employee organization any of whose employees or members are covered by the plan; and (iv) the owner of an IRA. Certain Parties in Interest (or

Disqualified Persons) that participate in a prohibited transaction may be subject to a penalty (or an excise tax) imposed pursuant to Section 502(i) of ERISA (or Section 4975 of the Code) unless a statutory or administrative exemption is available. Without an exemption an IRA owner may disqualify his or her IRA.

Certain transactions involving the purchase, holding or transfer of the 2026 Bonds might be deemed to constitute prohibited transactions under ERISA and Section 4975 of the Code if assets of the Authority were deemed to be assets of a Benefit Plan. Under final regulations issued by the United States Department of Labor (the "Plan Assets Regulation"), the assets of the Authority would be treated as plan assets of a Benefit Plan for the purposes of ERISA and Section 4975 of the Code if the Benefit Plan acquires an "equity interest" in the Authority and none of the exceptions contained in the Plan Assets Regulation is applicable. An equity interest is defined under the Plan Assets Regulation as an interest in an entity other than an instrument which is treated as indebtedness under applicable local law and which has no substantial equity features. Although there is little guidance on this matter, it appears that the 2026 Bonds should be treated as debt without substantial equity features for purposes of the Plan Assets Regulation. This determination is based upon the traditional debt features of the 2026 Bonds, including the reasonable expectation of purchasers of 2026 Bonds that the 2026 Bonds will be repaid when due, traditional default remedies, as well as the absence of conversion rights, warrants and other typical equity features.

However, without regard to whether the 2026 Bonds are treated as an equity interest for such purposes, though, the acquisition or holding of 2026 Bonds by or on behalf of a Benefit Plan could be considered to give rise to a prohibited transaction if the Authority or the Trustee, or any of their respective affiliates, is or becomes a Party in Interest or a Disqualified Person with respect to such Benefit Plan.

Most notably, ERISA and the Code generally prohibit the lending of money or other extension of credit between an ERISA Plan or Tax-Favored Plan and a Party in Interest or a Disqualified Person, and the acquisition of any of the 2026 Bonds by a Benefit Plan would involve the lending of money or extension of credit by the Benefit Plan. In such a case, however, certain exemptions from the prohibited transaction rules could be applicable depending on the type and circumstances of the plan fiduciary making the decision to acquire a 2026 Bond. Included among these exemptions are: Prohibited Transaction Class Exemption ("PTCE") 96-23, regarding transactions effected by certain "in-house asset managers"; PTCE 90-1, regarding investments by insurance company pooled separate accounts; PTCE 95-60, regarding transactions effected by "insurance company general accounts"; PTCE 91-38, regarding investments by bank collective investment funds; and PTCE 84-14, regarding transactions effected by "qualified professional asset managers." Further, the statutory exemption in Section 408(b)(17) of ERISA and Section 4975(d)(20) of the Code provides for an exemption for transactions involving "adequate consideration" with persons who are Parties in Interest or Disqualified Persons solely by reason of their (or their affiliate's) status as a service provider to the Benefit Plan involved and none of whom is a fiduciary with respect to the Benefit Plan assets involved (or an affiliate of such a fiduciary). There can be no assurance that any class or other exemption will be available with respect to any particular transaction involving the 2026 Bonds, or that, if available, the exemption would cover all possible prohibited transactions.

By acquiring a 2026 Bond (or interest therein), each purchaser and transferee (and if the purchaser or transferee is a plan, its fiduciary) is deemed to represent and warrant that either (i) it is not acquiring the 2026 Bond (or interest therein) with the assets of a Benefit Plan, Governmental Plan or Church Plan; or (ii) the acquisition and holding of the 2026 Bond (or interest therein) will not give rise to a nonexempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code or Similar Laws. A purchaser or transferee who acquires 2026 Bonds with assets of a Benefit Plan represents that such purchaser or transferee has considered the fiduciary requirements of ERISA, the Code or Similar Laws and has consulted with counsel with regard to the purchase or transfer.

Because the Authority, the Trustee, the Underwriters or any of their respective affiliates may receive certain benefits in connection with the sale of the 2026 Bonds, the purchase of the 2026 Bonds using plan assets of a Benefit Plan over which any of such parties has investment authority or provides investment advice for a direct or indirect fee may be deemed to be a violation of the prohibited transaction rules of ERISA or Section 4975 of the Code or Similar Laws for which no exemption may be available. Accordingly, any investor considering a purchase of 2026 Bonds using plan assets of a Benefit Plan should consult with its counsel if the Authority, the Trustee or the

Underwriters or any of their respective affiliates has investment authority or provides investment advice for a direct or indirect fee with respect to such assets or is an employer maintaining or contributing to the Benefit Plan.

Any ERISA Plan fiduciary considering whether to purchase the 2026 Bonds on behalf of an ERISA Plan should consult with its counsel regarding the applicability of the fiduciary responsibility and prohibited transaction provisions of ERISA and Section 4975 of the Code to such an investment and the availability of any of the exemptions referred to above. Persons responsible for investing the assets of Tax-Favored Plans that are not ERISA Plans should seek similar counsel with respect to the prohibited transaction provisions of the Code and the applicability of Similar Laws.

UNDERWRITING

Pursuant to the provisions of a Bond Purchase Agreement, J.P. Morgan Securities LLC (in such capacity, the “Representative”), on its own behalf and on behalf of BofA Securities, Inc., Barclays Capital Inc., Academy Securities, Inc., Goldman Sachs & Co. LLC, TD Financial Products LLC, Truist Securities, Inc., and Wells Fargo Bank, National Association (together with the Representative, the “Underwriters”), have agreed, subject to certain conditions, to purchase the 2026 Bonds from the Authority at the price of $________, representing the aggregate principal amount of the 2026 Bonds, plus [net] original issue premium of $________, less an underwriters’ discount of $________. The Underwriters’ obligations are subject to certain conditions precedent, and they will be obligated to purchase all 2026 Bonds if any 2026 Bonds are purchased. The public offering prices may be changed, from time to time, by the Underwriters.

Certain of the Underwriters may have entered into distribution agreements with other broker-dealers (that have not been designated by the Authority as Underwriters) for the distribution of the 2026 Bonds at the original issue prices. Such agreements generally provide that the relevant Underwriter will share a portion of its underwriting compensation or selling concession with such broker-dealers.

The Underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage, and other financial and non-financial activities and services. Certain of the Underwriters and their respective affiliates have provided and may in the future provide, a variety of these services to the Authority and to persons and entities with relationships with the Authority, for which they received or will receive customary fees and expenses. For a discussion of credit facilities provided by certain of the Underwriters or their affiliates to the Authority, see “Commercial Paper Notes” and “Revolving Credit Agreements” under “THE AUTHORITY – Outstanding Indebtedness – Subordinated Debt.”

In the ordinary course of their various business activities, the Underwriters and their respective affiliates, officers, directors, and employees may purchase, sell, or hold a broad array of investments and actively trade securities, derivatives, loans, commodities, currencies, credit default swaps, and other financial instruments for their own account and for the accounts of their customers, and such investment and trading activities may involve or relate to assets, securities, and/or instruments of the Authority (directly, as collateral securing other obligations or otherwise), and/or persons and entities with relationships with the Authority. The Underwriters and their respective affiliates may also communicate independent investment recommendations, market color, or trading ideas, and/or publish or express independent research views in respect of such assets, securities or instruments and may at any time hold, or recommend to clients that they should acquire, long, and/or short positions in such assets, securities, and instruments.

FINANCIAL ADVISOR

PFM Financial Advisors LLC is acting as municipal advisor (the “Municipal Advisor”) to the Authority in connection with the issuance of the 2026 Bonds. The Municipal Advisor has not audited, authenticated, or otherwise verified the information set forth in this Official Statement or the other information available from the Authority with respect to the appropriateness, accuracy, and completeness of the disclosure of such information, and the

Municipal Advisor makes no guarantee, warranty, or other representation on any matter related to such information. The Municipal Advisor is an independent municipal advisory and consulting organization and is not engaged in the business of underwriting, marketing, or trading of municipal securities or any other negotiable instruments.

INDEPENDENT AUDITORS

The financial statements as of December 31, 2024 and 2023, and for each of the two years in the period ended December 31, 2024, included in this Official Statement, have been audited by PricewaterhouseCoopers LLP, independent auditors, as stated in their report appearing herein.

See APPENDIX A – "REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS" attached hereto.

The unaudited 2025 and 2024 results included in this Official Statement have been prepared by, and are the responsibility of, the Authority's management. PricewaterhouseCoopers LLP has not performed an audit, review, or compilation with respect to the accompanying unaudited 2025 and 2024 results. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto.

RATINGS

S&P Global Ratings ("S&P"), Moody's Investors Service, Inc. ("Moody's"), and Fitch Ratings ("Fitch") have assigned ratings to the 2026 Bonds of "A-", "A3," and "A-", respectively.

Such ratings reflect only the views of such organizations and any desired explanation of the significance of such ratings or other statements given by the rating agencies with respect thereto should be obtained from the rating agency furnishing the same, at the following addresses: Fitch Ratings, Hearst Tower, 300 West 57th Street, New York, New York 10019, Moody's Investors Service, Inc., 7 World Trade Center, 250 Greenwich Street, New York, New York 10007 and S&P Global Ratings, 55 Water Street, New York, New York 10041. The Authority has furnished to the rating agencies information, including information not included in this Official Statement, about the Authority and the 2026 Bonds. Generally, a rating agency bases its rating and outlook on the information and materials furnished to it and on investigations, studies, and assumptions of its own. There is no assurance such ratings for the 2026 Bonds will continue for any given period of time or that any of such ratings will not be revised downward or withdrawn entirely by any of the rating agencies, if, in the judgment of such rating agency or agencies, circumstances so warrant. Those circumstances may include, among other things, changes in or unavailability of information relating to the Authority. Any such downward revision or withdrawal of such ratings may have an adverse effect on the market price of the 2026 Bonds.

VERIFICATION OF MATHEMATICAL COMPUTATIONS

Integrity Public Finance Consulting LLC will verify the accuracy of the mathematical computations of the adequacy of the maturing principal of and interest on Permitted Investments, together with certain cash balances, held under the Escrow Deposit Agreement with respect to the Refunded Bonds, to pay the principal of the Refunded Bonds on the redemption dates therefor and to pay accrued interest thereon to the redemption dates.

APPROVAL OF LEGAL PROCEEDINGS

The issuance of the 2026 Bonds is subject to the approval of Burr Forman McNair LLP, Charleston, South Carolina, Bond Counsel and delivery of the approving opinion of Bond Counsel in substantially the form set forth in APPENDIX E – "PROPOSED FORMS OF BOND COUNSEL OPINION" attached hereto. Certain legal matters will be passed upon for the Authority by Nixon Peabody LLP, New York, New York, Disclosure Counsel to the Authority. Certain legal matters will be passed on for the Authority by Carmen H. Thomas, the Authority's Vice President, Chief Legal Officer, and General Counsel, and for the Underwriters by their counsel, Orrick, Herrington & Sutcliffe LLP, New York, New York.

CONTINUING DISCLOSURE

The Authority has authorized and will execute a Continuing Disclosure Agreement simultaneously with the delivery of the 2026 Bonds (the "Continuing Disclosure Agreement") to assist the Underwriters in complying with Rule 15c2-12 of the SEC ("Rule 15c2-12"). A proposed form of the Continuing Disclosure Agreement is included as APPENDIX F – "PROPOSED FORM OF CONTINUING DISCLOSURE AGREEMENT" attached hereto.

Pursuant to the Continuing Disclosure Agreement, the Authority will covenant for the benefit of the Holders and the "Beneficial Owners" (as hereinafter defined) of the 2026 Bonds to provide certain financial information and operating data relating to the System by not later than six months (presently, by each June 30) after the end of each of the Authority's fiscal years, commencing with the report for the fiscal year ending December 31, 2025 (the "Annual Report"), and to provide notices of the occurrence of certain enumerated events with respect to the 2026 Bonds. The Annual Report will be filed by, or on behalf of, the Authority with the MSRB through its EMMA system. The notices of such enumerated events will be filed by, or on behalf of, the Authority with the MSRB. The specific nature of the information to be contained in the Annual Report or the notices of enumerated events is set forth in the form of the Continuing Disclosure Agreement.

As provided in the Continuing Disclosure Agreement, failure by the Authority to comply with any provision of the Continuing Disclosure Agreement does not constitute an event of default under the Revenue Obligation Resolution; however, any Holder or Beneficial Owner of the 2026 Bonds may take such actions as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause the Authority to comply with its obligations under the Continuing Disclosure Agreement. "Beneficial Owner" is defined in the Continuing Disclosure Agreement to mean any person which (a) has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of, any 2026 Bonds (including persons holding 2026 Bonds through nominees, depositories or other intermediaries), or (b) is treated as the owner of any 2026 Bonds for federal income tax purposes. If any person seeks to cause the Authority to comply with its obligations under the Continuing Disclosure Agreement, it is the responsibility of such person to demonstrate that it is a "Beneficial Owner" within the meaning of the Continuing Disclosure Agreement.

Except as described in the following paragraph, the Authority represents that, in the previous five years, it has not failed to comply, in all material respects, with any previous undertaking in a written contract or agreement entered into under Rule 15c2-12.

In September 2021, the Authority failed to file notice in a timely manner with respect to the incurrence of a "Financial Obligation", as defined in Rule 15c2-12, that on September 9, 2021, the Authority and Bank of America entered into a First Amendment to Revolving Credit Agreement (the "First Amendment") to extend the expiration date of the Bank of America Credit Agreement to December 10, 2021. On November 22, 2021, the Authority filed the notice of having entered into the First Amendment and additionally filed a notice of late filing regarding entering into the First Amendment. The Authority has become aware that some information that was made available in a timely manner on the EMMA system pursuant to the Authority's continuing disclosure obligations was not linked to the CUSIP numbers for certain series of the Authority's Obligations. The Authority has corrected this issue.

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MISCELLANEOUS

The agreements of the Authority with the owners of the 2026 Bonds are fully set forth in the Revenue Obligation Resolution. This Official Statement is not to be construed as a contract with the purchasers of the 2026 Bonds. This Official Statement has been approved by the Board.

The information contained in this Official Statement has been compiled or prepared from information obtained from the Authority and other sources deemed to be reliable and, while not guaranteed as to completeness or accuracy, is believed to be correct as of the date hereof. Any statements involving matters of opinion, whether or not expressly so stated, are intended as such and not as representations of fact.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

By: ____

President and Chief Executive Officer

APPENDIX A

REPORT OF THE AUTHORITY'S FINANCIAL STATEMENTS

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90TH ANNIVERSARY

santee cooper®

Celebrating 90 Years of ***POWERING*** SOUTH CAROLINA

Annual Report 2024

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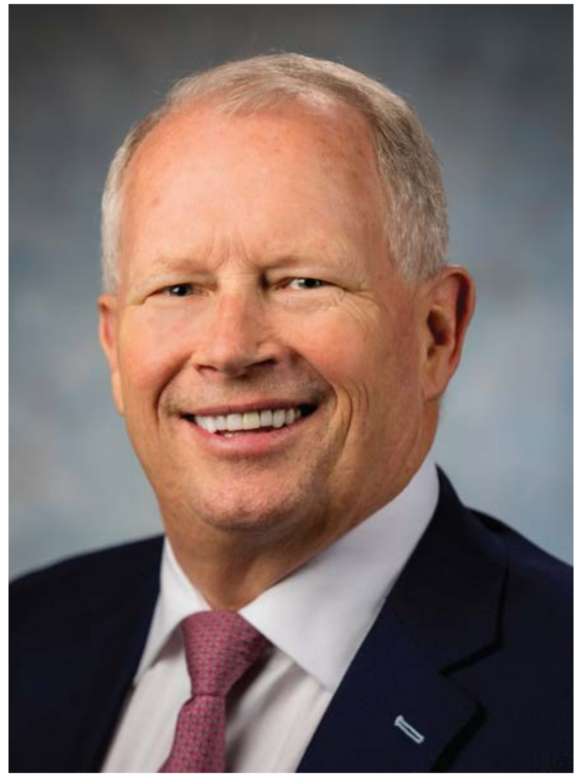
Letter from the Chairman and CEO

Peter McCoy, *Chairman*



Jimmy Staton, *President and CEO*

2024 was a milestone year in many ways for Santee Cooper. It marked 90 years since this state-owned electric and water utility was created by the South Carolina General Assembly, years marked by dramatic growth in our scope of work and an unwavering commitment to why we do that work: our customers and the people of this great state. It was also the 30th anniversary year for our Lake Moultrie Regional Water System, a model for how multi-agency government cooperation can deliver real benefits to communities.

The year was dominated by statewide discussions about South Carolina's pressing need for additional electric capacity to meet rapid escalation in load growth, and Santee Cooper advanced our own plans to ensure we continue to meet our customers' electric needs with best-in-class reliability and best-in-state affordability.

Customers and Community

The key benefit we provide our electric customers is reliable, affordable power that is delivered safely. Santee Cooper's typical residential customer has the lowest average monthly bill in South Carolina, compared to customers of the state's other major electric utilities.

Santee Cooper delivers that power with best-in-class reliability. The average residential customer was without power fewer than 26 minutes in 2024, a result that places Santee Cooper distribution reliability among the top 10% nationally, compared to approximately 500 peer utilities. Our transmission system also performed within the top 10% of its peer group.

We continue to offer innovative customer programs, including rebates for equipment that helps our customers be more energy efficient. We also provide house calls to help customers assess their energy-efficiency opportunities. In 2024, we partnered with The Sustainability Institute of North Charleston to bring additional focus and opportunity to income-eligible customers, a focus that is continuing into 2025.

Santee Cooper's Regional Water System on Lake Moultrie, which serves Summerville, Goose Creek, Moncks Corner and Berkeley County, was honored for its work. The system received the 25-Year Directors Award from the Partnership for Safe Water, a program developed by the Environmental Protection Agency, American Water Works Association and partner agencies.

The Lake Moultrie system and its younger sibling, the Lake Marion Regional Water System, are growing as we provide safe drinking water to support customers and the economic development that supports our communities.

And when our team was not at work, they volunteered, clocking over 27,000 hours to help lift up our communities in 2024.

That volunteerism benefited public school students, clients of organizations supported by area United Ways, neighbors who benefit from medical research funded by the American Cancer Society, American Heart Association and similar organizations, children who enjoy community sports leagues and recreation opportunities, and many others.

Our annual Celebrate The Season holiday festival and lights driving tour raised nearly $136,000 for charities in Berkeley County, and our employee campaigns topped all others for United Ways in Horry County and metropolitan Charleston.

Mother Nature's Impacts

Mother Nature delivered storms during 2024 that created some challenges on the Santee Cooper system.

Winter Storm Finn brought a wind-and-rain event to South Carolina on Tuesday, Jan. 9. Our transmission system experienced outages affecting five electric cooperatives, and we worked closely with those cooperatives to identify the faults and quickly reenergized their lines. More than 4,400 distribution customers lost power as well. All outages were restored by that Wednesday night.

Hurricane Helene brought incredible devastation to South Carolina, especially in the Upstate. The storm locked out lines and delivery points across approximately 20% of Santee Cooper's system, which was mostly reenergized in two days.

Distribution crews restored about 6,700 customer outages caused by Helene within a couple of days and immediately set out to help other utilities across the state. Between Helene and the less impactful Hurricane Milton, our crews spent weeks helping our fellow utilities restore power across South Carolina.

Flooding was a big part of Helene's impact, and that caused a significant amount of water to flow from the Upstate into the Santee Cooper Lakes. We conducted an extensive controlled spill to ensure the integrity of our dams and dikes.

Capacity Needs
South Carolina, the Southeast and most of the country are looking for solutions to an increasing need for additional electric capacity, the result of closing older generating units, the proliferation of energy-intensive manufacturing and data centers, and electrification of the transportation sector.

For our part, Santee Cooper is delivering short-term solutions while we plan for long-term generation needs. This starts with continuing to invest in our existing generating units to ensure they remain reliable, efficient and environmentally compliant.

In addition to our current generating portfolio, we are adding long-term purchased power contracts and expanding Rainey Generating Station in Anderson County. We will add approximately 200 megawatts (MW) of capacity at Rainey by the end of 2027, primarily through installing equipment that will generate additional power by capturing existing waste heat. This conversion process will provide the extra power without increasing the emissions rate at this natural gas-fueled station.

We are working with Central Electric Power Cooperative, Inc., our largest wholesale customer, to add additional solar power to the system and issued a request for proposals in 2024 as the first step toward significant solar additions.

Additionally, we continue to plan for a new natural gas combined cycle station, ideally to be built with Dominion Energy South Carolina and be available in the early 2030s. A jointly built project would provide economies of scale to benefit our customers. Santee Cooper is seeking the required legislative approval to partner with Dominion.

All of these initiatives are part of the 2024 Update to our 2023 Integrated Resource Plan, an update we filed with the Public Service Commission in September.

Meanwhile, and in response to growing interest among state leaders watching as other entities restart nuclear generating stations, we planned an RFP process related to the partially constructed V.C. Summer Units 2 and 3. We are soliciting interest from entities who may want to buy the assets and resume construction. Santee Cooper does not intend to own or operate those units. Our motivation is to produce value from those assets for the benefit of our customers and the state.

Financial Highlights
Santee Cooper realized significant benefits for our customers through a very successful bond transaction that refinanced $925 million of outstanding debt. That transaction yielded 11% net present value savings for customers ($180 million in gross savings) over the life of the refunded bonds. The transaction was six times oversubscribed by potential investors, pointing to the market value attached to Santee Cooper bond opportunities.

In rating the bond transaction ahead of the sale, Fitch improved its outlook on Santee Cooper debt from negative to stable.

Santee Cooper completed the *Cook* Settlement-imposed rate freeze on Dec. 31, 2024. In preparation, we began a rate adjustment process early in 2024, marking our first rate adjustment process since 2015. The process was comprehensive and transparent, including a four-month public comment period that included several public hearings and a website-based comment portal to enhance customers' ability to offer input. We received more than 500 comments from customers and other interested parties, and we adjusted our rate proposal based on that feedback.

In December, our Board of Directors approved new rates with an average 4.9% increase across all retail customer classes. The Board also approved a new rate structure for residential customers that offers improved customer control over their monthly bills. That new RG-25 rate adds a demand charge that applies to the highest "peak" hour of use each month and lowers the cost of energy by 34% for all hours – meaning customers can still use the same amount of energy as they normally would, shift their use of high-energy-consuming appliances to non-peak hours, and potentially reduce their bills. The monthly bill for a typical residential customer will increase, on average, $11 a month if they make no changes in when they use electricity.

Value to the State

As a state-owned utility, Santee Cooper works to provide benefits across the state, in keeping with our mission to be the leading resource for improving the quality of life for all South Carolinians. We focus on promoting economic development, for example, and work with state and local entities, the state's electric cooperatives and other partners focused on improving economic prosperity.

Santee Cooper's Camp Hall Commerce Park represents a major investment in this work, and a 2024 economic impact study put the Berkeley County park's current annual economic impact at $3.8 billion across South Carolina, corresponding to 6,364 jobs and $479.4 million in labor income. Conducted by Joseph C. Von Nessen Ph.D., Research Economist at the University of South Carolina Darla Moore School of Business, the study concludes that at full development (after 2035), Camp Hall will contribute $7.9 billion a year in state economic impact, of which$7.3 billion is in the Charleston metropolitan region. Business Facilities Magazine ranked Camp Hall the top commerce park in the Southeast and No. 6 in the country. Santee Cooper began developing Camp Hall in 2016, and today it includes anchor tenant Volvo Car USA and facilities announced by Redwood Materials and others.

In 2024, Santee Cooper helped secure announced industrial projects around the state totaling $3.1 billion in capital investment and 857 new jobs for South Carolina. Since 1988, Santee Cooper has worked with the state's electric cooperatives and other economic development entities to generate more than $25 billion in capital investment and helped bring approximately 90,000 new jobs to South Carolina.

We also serve as the South Carolina entity administering a formula grant provided for South Carolina grid resilience under the federal Bipartisan Infrastructure Law (BIL), Section 40101(d). In 2024, we awarded funds for 17 projects proposed by electric cooperatives and municipal utilities using 2022 and 2023 BIL funding, and in late 2024, we recommended 14 additional projects to the U.S. Department of Energy for final approval using 2024 BIL funds.

Conclusion

Santee Cooper has proudly served South Carolina – and South Carolinians – for 90 years. As we look to the next 90, we are strategically planning for, and investing in, solutions to future energy, water and other needs that will strengthen communities across South Carolina.

Thank you,

Peter McCoy
Chairman

Jimmy Staton
President and CEO

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CORPORATE STATISTICS

System Data 2024

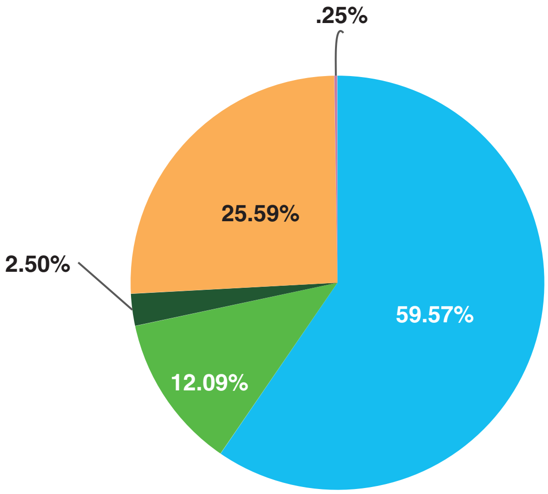
Miles of transmission system lines[1]:	**5,271**
Miles of distribution system lines:	**3,195**
Number of transmission substations:	**93**
Number of distribution substations:	**60**
Number of Central Electric Power Cooperative, Inc (CEPCI) Delivery Points (DPs):	**427**

[1] Includes Central-owned transmission lines

	2024	2023	2022	2021	2020
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,940,807**	$1,888,400	$1,974,737	$1,854,350	$1,689,760
Total Expenses & Interest Charges	**$2,089,351**	$1,744,573	$1,960,898	$1,801,232	$1,583,275
Other	**$232**	($8,433)	($1,026)	$3,146	($54,431)
Reinvested Earnings	**($148,312)**	$135,394	$12,813	$56,264	$52,054
OTHER FINANCIAL *(Excluding CP and Other)*					
Debt Service Coverage *(prior to Distribution to State and Special Item, includes Cook Deferred Expenses)*[1]	**1.09**	1.95	1.27	1.27	1.46
Debt / Equity Ratio	**77/23**	76/24	77/23	76/24	76/24
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**216,467**	212,597	204,766	198,694	193,930
Military and Large Industrial	**27**	27	27	27	27
Wholesale - on system	**4**	4	4	4	4
Wholesale - off system	**3**	4	4	4	4
Total Customers	**216,501**	212,632	204,801	198,729	193,965
Generation (MWh):					
Coal	**12,168,545**	11,096,020	9,953,263	10,441,460	8,502,014
Nuclear	**2,468,680**	2,499,418	2,863,279	2,323,542	2,569,684
Hydro	**510,439**	464,761	418,764	503,461	756,388
Natural Gas and Oil	**5,227,020**	5,588,689	5,694,732	5,020,130	5,471,117
Landfill Gas & Renewables	**50,364**	63,584	47,651	49,039	47,077
Total Generation (MWh)	**20,425,048**	19,712,472	18,977,689	18,337,632	17,346,280
Purchases, Net Interchanges, etc. (MWh)	**7,602,921**	7,021,907	7,891,502	6,867,283	5,723,215
Wheeling, Interdepartmental, and Losses	**(877,471)**	(549,448)	(644,818)	(603,873)	(836,321)
Total Energy Sales (MWh)	**27,150,498**	26,184,931	26,224,373	24,601,042	22,233,174
Annual Degree Days	**4,079**	3,741	4,250	4,062	3,907
Summer Generating Capacity (MW)	**5,163**	5,170	5,075	5,115	5,110
Winter Generating Capacity (MW)	**5,388**	5,388	5,293	5,343	5,338
Territorial Peak Demand (MW), Summer	**4,949**	4,940	4,746	4,505	4,467
Territorial Peak Demand (MW), Winter	**5,325**	4,664	5,342	4,634	4,456

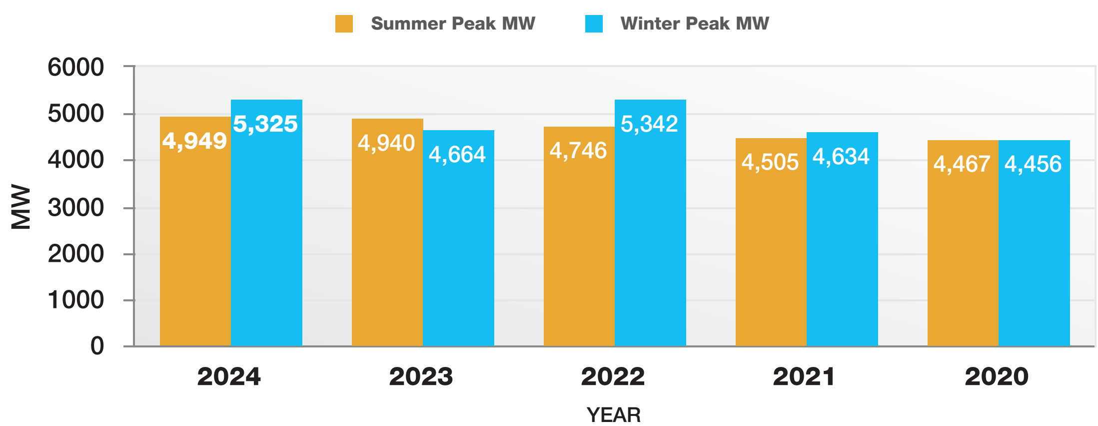
[1] See Note 5 - Cook Settlement as to Rates

2024 GENERATION BY FUEL MIX

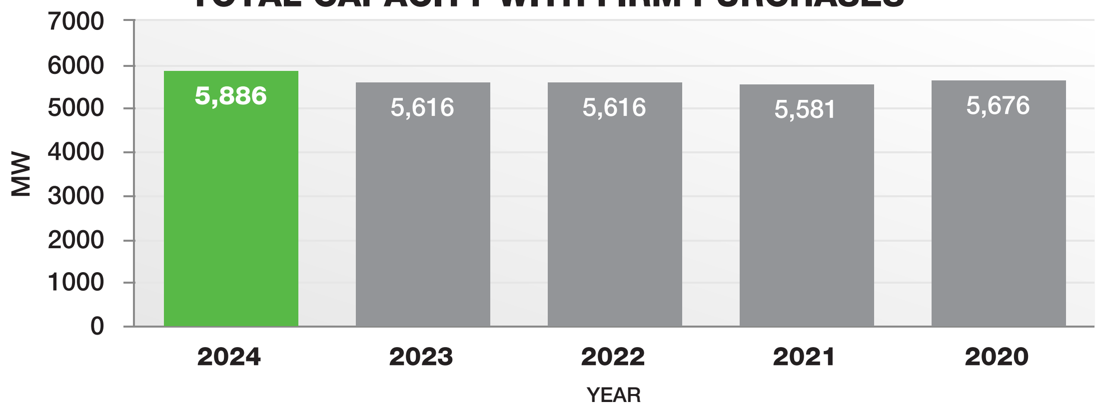


Source		MWh
Coal	59.57%	12,168,545
Nuclear	12.09%	2,468,680
Hydro	2.50%	510,439
Natural Gas and Oil	25.59%	5,227,020
Total Renewables	0.25%	50,364
	100.00%	20,425,048

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 public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

Charles H. Leaird
Chairman
2024 Audit Committee

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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 years ended December 31, 2024 and 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, 2024 and 2023, and the respective changes in financial position and, where applicable, cash flows thereof for the years 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.

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

PricewaterhouseCoopers LLP, 1075 Peachtree Street, Suite 2600, Atlanta, GA 30309
T: (678) 419 1000, www.pwc.com/us

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 on pages 15 through 30, schedule of proportionate share of the net pension liability on page 95, schedule of pension plan contributions on page 96, schedule of changes in net OPEB liability and related ratios on page 97, schedule of OPEB contributions on page 98, and schedule of investment returns on page 98 be presented to supplement the basic financial statements. Such information is the responsibility of management, 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 14, 2025

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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.

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 5,163 megawatts (MW) consisting of 3,465 MW of coal-fired capacity, 1,203 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, 2024, 2023 and 2022 are summarized below

	2024	2023	2022
		(Thousands)	
ASSETS & DEFERRED OUTFLOWS OF RESOURCES			
Capital assets	**$ 5,410,535**	$ 5,095,612	$ 5,008,163
Current assets	**1,467,106**	1,304,252	1,568,740
Other noncurrent assets	**4,692,207**	4,917,531	4,788,349
Deferred outflows of resources	**757,674**	829,286	976,711
Total assets & deferred outflows of resources	**$ 12,327,522**	$ 12,146,681	$ 12,341,963
LIABILITIES & DEFERRED INFLOWS OF RESOURCES			
Long-term debt - net	**$ 7,961,634**	$ 7,605,551	$ 7,573,550
Current liabilities	**650,884**	595,916	672,284
Other noncurrent liabilities	**1,081,511**	1,124,911	1,239,117
Deferred inflows of resources	**550,873**	569,951	723,093
Total liabilities & deferred inflows of resources	**$ 10,244,902**	$ 9,896,329	$ 10,208,044
NET POSITION			
Net invested in capital assets	**$ 1,919,010**	$ 2,001,334	$ 2,040,738
Restricted for debt service	**15,766**	12,182	20,698
Unrestricted	**147,844**	236,836	72,483
Total net position	**$ 2,082,620**	$ 2,250,352	$ 2,133,919
Total liabilities, deferred inflows of resources & net position	**$ 12,327,522**	$ 12,146,681	$ 12,341,963

2024 Compared to 2023

The primary changes in the Authority's financial condition as of December 31, 2024 and 2023 were as follows:

Assets and Deferred Outflows of Resources

Total assets and deferred outflows of resources increased $180.8 million during 2024 due to increases of $314.9 million in capital assets, and $162.9 million in current assets. These increases were offset by decreases of $225.3 million in other noncurrent assets and $71.6 million in deferred outflows of resources.

The increase in capital assets of $314.9 million was primarily due to capital construction spending for the Effluent Limitation Guidelines (ELGs) systems along with large transmission related projects.

The increase in current assets of $162.9 million was primarily due to a net increase in unrestricted and restricted cash and investments of $67.7 million. The net increases were caused mainly from proceeds received from the 2024 A & C new money issue in July 2024. Regulatory assets - nuclear increased $62.7 million due to higher principal payments for nuclear debt coming due in 2025. Materials and supplies increased $36.0 million driven by inflationary trends in the market and inventory build up to support the 10 year capital plan.

Accounts receivables increased $30.2 million, primarily caused by increases in the Central Electric Power Cooperative, retail and billable receivables. Regulatory assets - Cook Settlement Exceptions increased $32.9 million due to a transfer from noncurrent for the amount Cook settlement exceptions we intend to collect in 2025. These increases were offset by a $60.7 million decrease in fuel stocks attributed to a reduction in coal receipts in 2024 resulting from increased inventory levels and reducing the amount of inventory we had on our stockpiles. Also, prepaid expenses and other current assets decreased by $6.0 million primarily due to a decrease in the deferred vacation leave account.

The decrease in other noncurrent assets of $225.3 million resulted mainly from a decrease of $109.7 million in the noncurrent regulatory asset - nuclear due to transfers to current and a $108.0 million decrease in the Cook Settlement Exceptions regulatory asset primarily due to a $75.1 million adjustment from December 31, 2023 to write down the regulatory asset to match the settlement agreement amount and a $32.9 million transfer to the current portion for the amount we intend to collect in 2025. Further adding to the decrease was a $4.8 million decrease in regulatory asset - OPEB resulting from the latest actuarial study. Other noncurrent assets netted to small variances between the years.

Deferred outflows of resources decreased $71.6 million, due mainly to decreases in the following line items. Deferred outflows - asset retirement obligation of $54.5 million decreased primarily due to continued ash pond removals offset by an adjustment to align our one-third nuclear related asset retirement obligations with the majority owner's decommissioning study, a decrease of $16.7 million in the deferred outflows - accumulated decrease in the fair value of hedging derivatives and a decrease of $6.1 million in deferred outflows - unamortized loss on refunded and defeased debt resulting primarily from normal amortization during 2024. These decreases were offset slightly by a $4.0 million increase in deferred outflows - pension and a $1.7 million increase in deferred outflows - OPEB.

Liabilities, Deferred Inflows of Resources & Net Position

Liabilities & deferred inflows of resources increased $348.6 million. This was due to an increase of $356.1 million in long-term debt - net and a $55.0 million increase in current liabilities. These increases were partially offset by a $43.4 million decrease in other noncurrent liabilities and a $19.1 million decrease in deferred inflows of resources.

Long-term debt - net increased $356.1 million. This resulted primarily from Revenue Obligations due to a net increase of $384.9 million attributed to the 2024 ABC Refunding and Improvement bond issues offset by transfers to the current portion of $129.9 million. Unamortized debt discounts and premiums increased by $66.5 million due mainly to the impact associated with the 2024 A & B Improvement and Refunding bond issues. Also, Long Term Revolving Credit Agreements increased by $36.0 million due to current period draws partially offset by $1.4 million from transfers to short term.

The increase in current liabilities of $55.0 million was due mainly to increases in the current portion - long term debt of $73.3 million and an increase of $38.3 million in accounts payable. These increases were partially offset by decreases of $47.0 million in other current liabilities and $10.9 million in commercial paper. The current portion - long term debt increased due to higher principal payments coming due in 2025 as compared to 2024. The accounts payable increase resulted from higher transmission and environmental related payable accounts. The decrease in other current liabilities was primarily a result of a decrease in the current mark to market loss liability account related to hedging derivatives, a decrease in the revenue adjustment account and a decrease in the payable account related to the corporate goals incentive program. The decrease in commercial paper was due to a decrease of $79.6 million from paydowns offset by new issuances of $68.7 million. In addition, there was a small increase of $1.2 million in accrued interest on long term debt.

The decrease in other noncurrent liabilities of $43.4 million resulted primarily from reductions in asset retirement obligations of $54.6 million related to ash pond remediation efforts offset by an adjustment to align our one third nuclear related asset retirement obligations with the majority owner's decommissioning study. Also contributing was a decrease in the net pension of $22.9 million. This resulted from the 2024 actuarial study updates associated with changes in investment return and discount assumptions for the current year. This was offset by a $20.6 million increase in construction fund liabilities due mainly to environmental and transmission projects and a $11.2 million increase in the net OPEB liability due to actuarial assumptions. Other items in this line item accounted for small net increases of approximately $2.3 million between the years being compared.

Deferred inflows of resources decreased $19.1 million due to a lower accumulated value in fair value of hedging derivatives of $16.2 million caused by lower mark to market gains associated with lower natural gas prices reducing future settle prices. There were also decreases of $11.2 million in deferred inflows - OPEB associated with changes in assumptions for investment experience in the 2024 actuarial study and deferred inflows - Toshiba settlement due to amortization of $8.9 million. These decreases were partially offset by increases in deferred inflows – pension of $14.2

million due changes in assumptions to the 2024 actuarial study and deferred inflows - nuclear decommissioning costs of $3.0 million.

The decrease in net position of $167.7 million was due to negative operating results of $148.3 million and the current year payment to the state of $19.4 million. This was impacted largely by the recent "Exceptions Dispute" settlement further discussed in Note 15- Subsequent Events. Unrestricted net position and net investment in capital assets decreased $89.0 million and $82.3 million, respectively. This was offset slightly by a $3.6 million increase in restricted net position.

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.

Results of Operations

Santee Cooper's Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2024, 2023 and 2022 are summarized as follows:

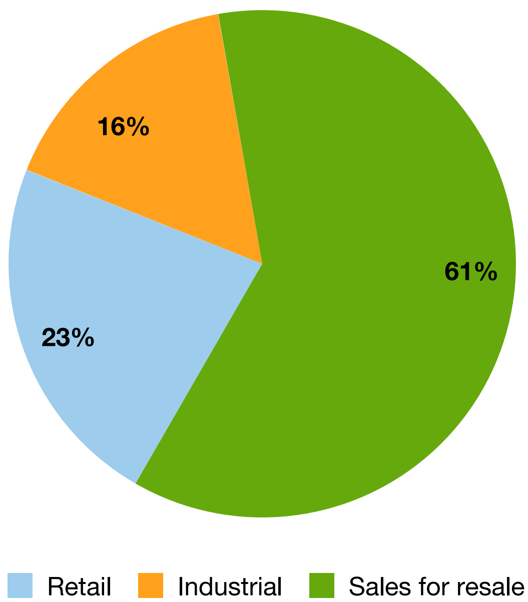
	2024	2023	2022
		(Thousands)	
Operating revenues	**$ 1,916,851**	$ 1,850,603	$ 1,949,050
Operating expenses	**1,764,307**	1,429,528	1,670,010
Operating income	**152,544**	421,075	279,040
Interest expense	**(325,044)**	(315,045)	(290,888)
Costs to be recovered from future revenue	**232**	(8,433)	(1,026)
Other income	**23,956**	37,797	25,688
Capital contributions and transfers	**(19,420)**	(18,961)	(17,675)
Change in net position	**$ (167,732)**	$ 116,433	$ (4,861)
Net position - beginning of period	**$ 2,250,352**	$ 2,133,919	$ 2,138,780
Ending net position	**$ 2,082,620**	$ 2,250,352	$ 2,133,919

2024 Compared to 2023

Operating Revenues

Comparing 2024 to 2023, operating revenues increased $66.2 million (4%), primarily from higher demand usage and energy sales of $33.5 million and $15.9 million, respectively. The impacts were largely due to higher cooling degree days (9%) resulting from warmer weather than the previous year. Other factors causing the increase included higher: (i) fuel rate revenues of $10.9 million; (ii) off system sales of $10.2 million; and (iii) other smaller revenue adjustment increases of $3.8 million between the two periods. Offsets to this were provided by lower energy related fixed cost rates and O&M rate revenues of $4.8 million and $2.8 million, respectively. For comparison, energy sales for 2024 and 2023 were 27.2 million megawatt hours (MWhs) and 26.2 million (MWhs), respectively.

2024 Revenues from Sales of Electricity*
by Customer Class



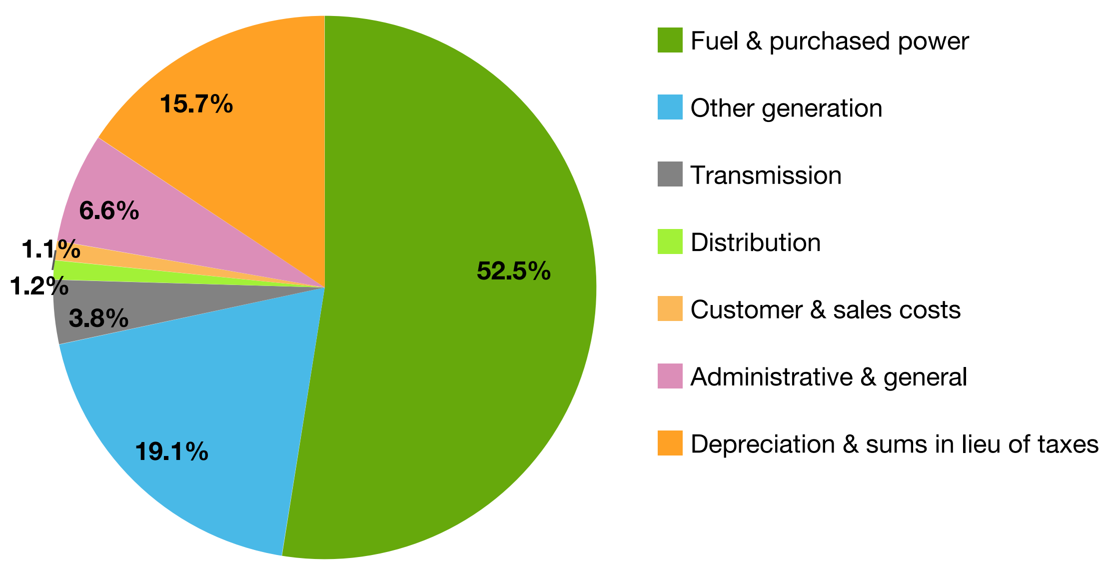
	2024	2023	2022
Revenues from Sales of Electricity*		(Thousands)	
Retail	**$ 427,024**	$ 409,762	$ 405,973
Industrial	**304,622**	306,602	386,211
Sales for resale	**1,149,346**	1,108,760	1,131,579
Totals	**$ 1,880,992**	$ 1,825,124	$ 1,923,763

*Excludes interdepartmental sales of $623 for 2024, $592 for 2023 and $615 for 2022.

OPERATING EXPENSES

Operating expenses for 2024 increased $333.7 million (23%) as compared to 2023. The increase was due primarily to higher fuel and purchased power resulting from lower fuel and purchased power credits of $302.3 million in the current year as compared to prior year, due to the Cook regulatory asset write down in the current year related to the Cook exceptions settlement agreement. (see Note 15- Subsequent Events) Purchased power increased $20.4 million due to replacement energy for outages and lower market prices as compared to prior year. These increases were offset by lower fuel of $53.1 million from outages and a less expensive energy mix versus prior year. Additional increases were: (i) higher non-fuel generation which showed an increase of $33.5 million from the Cook regulatory asset write down in the current year related to the pending Cook exceptions settlement agreement and higher expenses associated with Winyah, Cherokee and Rainey outages, increased Cross and Winyah repetitive maintenance and tech services and increased Cherokee operations expenses. These increases in non-fuel generation were offset by lower expenses associated with gypsum processing due to underuns; (ii) administrative and general increased $21.5 million primarily due to the Cook regulatory asset write down in the current year related to the pending Cook exceptions settlement agreement and increased operational expenses due to securitization costs previously incurred to evaluate potential debt securitization, being moved to O&M as well as increased expenses associated with grant administration and environmental services; and (iii) transmission increased $8.6 million primarily from higher outside transmission costs. Other small changes netted to the remaining variance.

2024 Electric Operating Expenses by Category



	2024	2023	2022
Electric Operating Expenses		(Thousands)	
Fuel & purchased power	**$ 922,330**	$ 652,622	$ 991,017
Other generation	**335,659**	302,186	229,251
Transmission	**67,168**	58,568	45,679
Distribution	**20,208**	20,076	21,515
Customer & sales costs	**19,976**	18,997	19,528
Administrative & general	**115,221**	93,758	84,099
Depreciation & sums in lieu of taxes	**275,303**	275,925	272,747
Totals	**$ 1,755,865**	$ 1,422,132	$ 1,663,836

Non-Operating Income (Expense)

Regulatory asset amortization and other income provided a combined increase to non-operating expense of $13.9 million, in 2024 as compared to 2023. This resulted primarily from higher amortization of the nuclear regulatory asset of $14.6 million, resulting from the 2024 B Refunding, a decrease in the fair value of investments of $3.5 million and lower Camp Hall sales of $2.7 million. Offsetting these increases were higher nuclear equipment sales of $7.0 million.

Interest charges increased $10.0 million, resulting primarily from higher long-term debt interest of $9.1 million from additional revolving credit agreement (RCA) draws and the 2024 A & C new money bond issues as well as lower Cook Settlement interest expense credits of $5.8 million due to the Cook exceptions regulatory asset write down in the current year related to the pending Cook exceptions settlement agreement. Somewhat offsetting this was an adjustment to customer deposit interest expense of $4.0 million.

Costs to be Recovered from Future Revenues ("CTBR") expense was lower year over year by $8.7 million because of higher CTBR depreciation related to debt funded assets in the current year.

Transfers represent dollars paid to the State.

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).

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.

Non-Operating Income (Expense)

Regulatory asset amortization and other income provided a combined decrease 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.

ECONOMIC DEVELOPMENT

The Authority and the electric industry continue to face challenges that impact the competitiveness and financial condition of the utility. As market conditions fluctuate, the Authority's mission continues to be to deliver affordable 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 marketing 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 $151 million throughout South Carolina in product development activities through low interest revolving loans and grants to public entities. In addition to 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 2024, including Birla Carbon in Orangeburg County, Google in Berkeley County and Dorchester Counties, and EnviroSep in Georgetown County.

CUSTOMER UPDATE AND MARKET CONDITIONS

The Authority's largest customer, Central Electric Power Cooperative, Inc, accounted for 60 percent of operating revenues in 2024. 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 obligate 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 costs after the impact of the Exceptions Agreement (see Note 15- Subsequent Events) in 2024 were higher than 2023. There were several weather-related issues including January's cold snap (reliability requirements and demand brought on more expensive generation), August's Tropical Storm Debby (flooded coal), and September's Hurricane Helene (transmission issues limited economic power purchases). Although below the maximum historical level, the Authority's coal inventory remained above the operational target range (800 thousand to 1.2 million tons) throughout the year. The Authority was able to utilize its newly acquired Cherokee Combined Cycle Unit (CCU) more than projected which helped mitigate the impact of unit outages at other generating stations; those included an unplanned Rainey CCU and extended VC Summer nuclear outage. Purchased energy market prices were generally lower than expected which enabled the Authority to reduce its own generation; however, when there were price spikes, the Authority was also able to switch back to its coal resources. The Authority participated in S.E.E.M trading and discounted Prepaid Natural Gas which both provided a modest savings. The Authority's 2024 system rate of $29.25/MWh was lower than its 2023 system rate but higher than its 2024 Budget projection by 5.1%. The 2024 system rate is in line with historical averages even though we have seen inflationary pressures throughout the past decade.

Legislative Matters

In 2024, South Carolina's Governor and the South Carolina General Assembly were focused on new energy infrastructure, including support for Santee Cooper to pursue a new natural gas combined cycle project with Dominion Energy.

In the South Carolina House of Representatives, a legislative committee appointed by the South Carolina Speaker of the House produced a bill authorizing Santee Cooper and Dominion Energy's pursuit of an NGCC joint build, proposing permitting reforms, and promoting regulatory reforms that are aligned with Santee Cooper's resource plan. This bill, H.5118, was introduced in February and did not pass before the legislature's May 9 regular session adjournment. The South Carolina Senate offered legislative language similar to H.5118 that supported Santee Cooper's resource plans and conducted hearings over the Summer and Fall to develop specific energy proposals for the 2025 legislative session. The Authority's CEO and staff participated in these state policy discussions. In 2025, Santee Cooper expects the South Carolina General Assembly will address energy legislation and approval for the joint build between Dominion Energy and the Authority. The South Carolina Governor may make appointments to the Santee Cooper board in 2025. These appointments could include the following seats on the board: 1) At Large (general); 2) 3rd congressional; 3) 5th congressional; 4) 7th congressional; 5) Horry County; and, 6) Georgetown County.

The South Carolina General Assembly's legislative session runs from January 14 to May 8, 2025.

CONTINUED FOCUS ON SUSTAINABILITY

The Authority remains committed to sustainability, recognizing its role in shaping a more resilient future for all of South Carolina. Our approach continues to be guided by the Authority's strategic objectives and our corporate mission to improve the quality of life for all South Carolinians.

Since 2023, the Authority's sustainability department has been tasked with developing and implementing an enterprise-wide strategic plan for sustainability based on internal and external stakeholder feedback, as well as leading the Authority's just transition efforts related to its planned retirement of the Winyah Generating Station and impacted stakeholders.

The Authority has advanced its enterprise-wide sustainability strategic planning initiatives through a stakeholder engagement process completed in early summer that utilized individual interviews, focus groups, and surveys to better understand stakeholder perspectives and expectations.

The Authority has also made significant progress in its just transition efforts related to Winyah and has onboarded a consulting firm to assist it with both internal and external engagement efforts.

The Authority remains focused on providing sustainable solutions 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 2024 Sustainability Report which will be available on April 1, 2025, 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 2024, 2023 and 2022 was as follows:

Approved in:		2024 Budget 2025-27		2023 Budget 2024-26		2022 Budget 2023-25
Capital Improvement Expenditures				(Thousands)		
Environmental Compliance [1]		**167,313**	$	395,157	$	286,757
General Improvements and Other [2]		**2,160,495**		1,501,622		818,716
Load and Resource Plan [3]		**1,058,158**		1,351		219,727
Totals	$	3,385,966	$	1,898,130	$	1,325,200

[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.

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.

Financing Activities

Santee Cooper issued $372.0 million of 2024 Tax-Exempt Improvement Series A and $73.0 million of 2024 Taxable Improvement Series C Revenue Obligation Bonds to fund our capital needs related to transmission, generation and distribution improvements on our system as well as environmental compliance. Santee Cooper also issued $865.1 million of 2024 Tax-Exempt Refunding Series B Revenue Obligation Bonds to refund approximately $925.2 million of existing currently callable tax-exempt debt. The refunding produced approximately $179.6 million in gross savings which resulted in $101.7 million in net present value savings.

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, 2024, Santee Cooper had $916.3 million of cash and investments, of which $406.4 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $218.9 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 $400.0 million as of December 31, 2024. As of December 31, 2024, the Authority had $172.5 million of commercial paper notes outstanding.

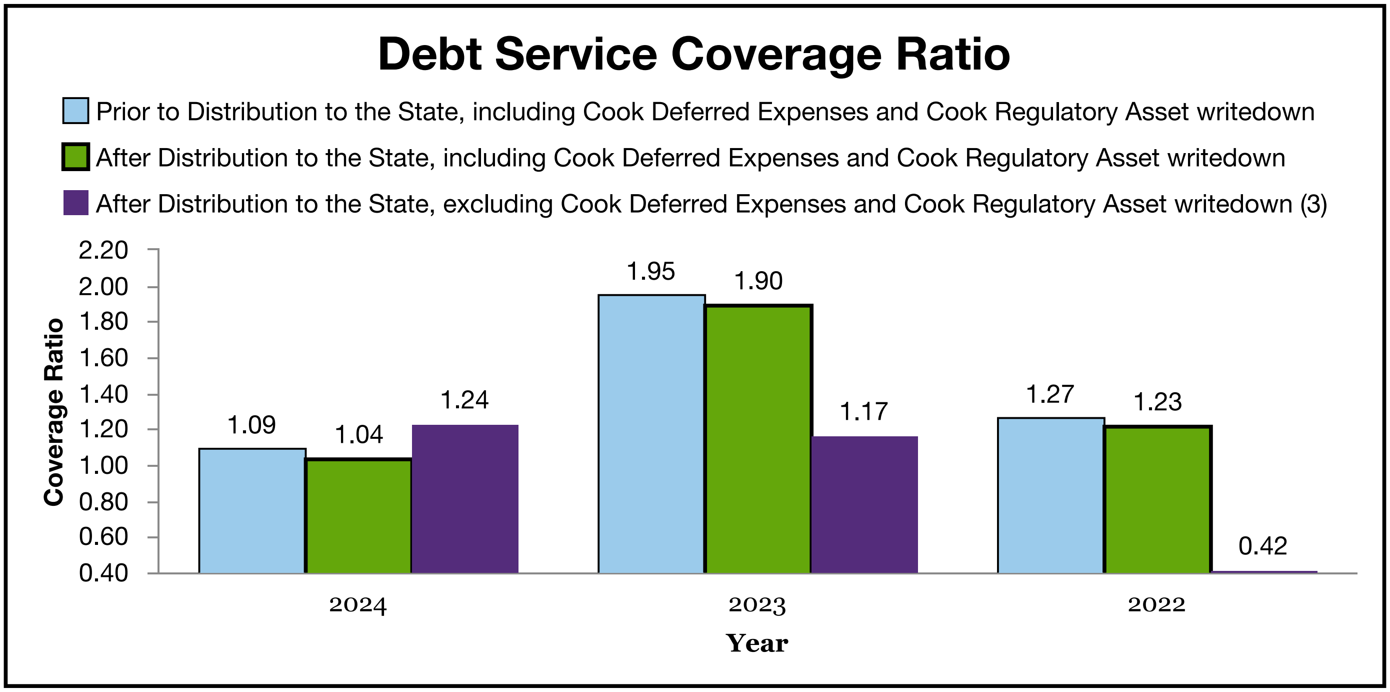
To obtain other funds, if needed, the Authority entered into Revolving Credit Agreements with various bank facilities. These agreements allow the Authority to borrow up to $800.0 million and expire at various dates. As of December 31, 2024, the Authority has borrowed $438.5 million under these agreements.

Reconciliations of Interest Charges

Years Ended December 31,		2024		2023
		(Thousands)		
Reconciliation of interest cost to interest expense:				
Total interest cost	**$**	**322,518**	$	309,079
Interest charged to fuel expense		0		0
Total interest expense on long-term debt	**$**	**322,518**	$	309,079
Reconciliation of interest cost to interest payments:				
Total interest cost	**$**	**322,518**	$	309,079
Accrued interest - current year		**(40,052)**		(38,770)
Accrued interest - prior year		**38,770**		40,456
Amortization income		**18,647**		17,955
Interest released by refundings		**(7,922)**		(101)
Cook Exceptions Regulatory Asset		**12,275**		17,297
Year-end manual accrual		**35**		(255)
Total interest payments on long term debt	**$**	**344,271**	$	345,661

DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2024, 2023 and 2022 is shown below:



[1] Excluding commercial paper and other.

[2] See Note 5 - *Cook Settlement*

[3] Debt service coverage ratios excluding the Cook deferred expenses and Cook regulatory asset write-down reflect cash basis which does not reflect deferral of the expenses in the year incurred and excludes the write down of the regulatory asset.

Debt Service Coverage - continued

Years Ended December 31,	**2024**	2023
	(Thousands)	
Operating revenues	**$ 1,916,851**	$ 1,850,603
Interest and investment revenue	**16,691**	16,939
Total revenues and income	**1,933,542**	1,867,542
Operating expenses (1)	**(1,764,307)**	(1,429,528)
Depreciation	**270,653**	272,161
Total expenses	**(1,493,654)**	(1,157,367)
Funds available for debt service prior to distribution to the State	**439,888**	710,175
Distribution to the State	**(19,420)**	(18,961)
Funds available for debt service after distribution to the State	**$ 420,468**	$ 691,214
Debt Service on Accrual Basis:		
Principal on long-term debt	**$ 61,463**	$ 36,431
Interest on long-term debt (1)	**341,165**	327,034
Long-term debt service paid from Revenues	**402,628**	363,465
Commercial paper and other principal and interest (1)	**5,469**	8,994
Total debt service paid from Revenues	**$ 408,097**	$ 372,459
Debt Service Coverage Ratio:		
Excluding commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses and Cook Regulatory Asset writedown	**1.09**	1.95
After distribution to the State, including Cook Deferred Expenses and Cook Regulatory Asset writedown	**1.04**	1.90
After distribution to the State, excluding Cook Deferred Expenses and Cook Regulatory Asset writedown (2)	**1.24**	1.17
Including commercial paper and other:		
Prior to distribution to the State, including Cook Deferred Expenses and Cook Regulatory Asset writedown	**1.07**	1.90
After distribution to the State, including Cook Deferred Expenses and Cook Regulatory Asset writedown	**1.03**	1.85
After distribution to the State, excluding Cook Deferred Expenses and Cook Regulatory Asset writedown (2)	**1.20**	1.13

[1]Operating expenses and interest charges are net of Cook deferred expenses and the Cook regulatory asset write down. See “Note 5 - Cook Settlement”

[2]Debt service coverage ratios excluding the Cook deferred expenses and Cook regulatory asset write-down reflect cash basis which does not reflect deferral of the expenses in the year incurred and excludes the write down of the regulatory asset

Bond Ratings

Bond ratings assigned by various agencies as of December 31, 2024, 2023 and 2022 were as follows:

Agency / Lien Level	2024	2023	2022
Fitch Ratings			
Revenue Obligations	**A-**	A-	A-
Commercial Paper	**F1**	F1	F1
Outlook	**Stable**	Negative	Negative
Moody's Investors Service, Inc.			
Revenue Obligations	**A3**	A3	A3
Commercial Paper	**P-1**	P-1	P-1
Outlook	**Stable**	Stable	Negative
Standard & Poor's Rating Services			
Revenue Obligations	**A-**	A-	A-
Commercial Paper	**A-1**	A-1	A-1
Outlook	**Negative**	Negative	Negative

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.

Statements of Net Position - Business - Type Activities
South Carolina Public Service Authority
As of December 31, 2024 and 2023

		2024		2023
		(Thousands)		
ASSETS				
Current assets				
Unrestricted cash and cash equivalents	**$**	**193,097**	$	236,702
Unrestricted investments		**213,276**		178,390
Restricted cash and cash equivalents		**94,397**		35,904
Restricted investments		**282,515**		264,587
Receivables, net		**205,419**		175,251
Materials inventory		**222,406**		186,373
Fuel inventory		**117,748**		178,484
Regulatory Asset - Cook Settlement Exceptions		**32,925**		0
Regulatory Asset - nuclear		**70,019**		7,296
Prepaid expenses and other current assets		**35,304**		41,265
Total current assets		**1,467,106**		1,304,252
Noncurrent assets				
Restricted cash and cash equivalents		**923**		336
Restricted investments		**132,115**		130,709
Capital assets				
Utility plant		**9,678,543**		9,530,569
Accumulated depreciation		**(5,061,632)**		(4,891,661)
Total utility plant-net		**4,616,911**		4,638,908
Construction work in progress		**767,866**		431,202
Other physical property-net		**25,758**		25,502
Total capital assets		**5,410,535**		5,095,612
Investment in associated companies		**32,886**		28,947
Costs to be recovered from future revenue		**213,759**		213,527
Regulatory asset - OPEB		**144,886**		149,694
Regulatory asset - nuclear		**3,529,138**		3,638,884
Regulatory assets - Cook Settlement Exceptions		**517,075**		625,110
Other noncurrent and regulatory assets		**121,425**		130,324
Total noncurrent assets		**10,102,742**		10,013,143
Total assets	**$**	**11,569,848**	$	11,317,395
DEFERRED OUTFLOWS OF RESOURCES				
Deferred outflows - pension	**$**	**27,578**	$	23,612
Deferred outflows - OPEB		**57,682**		56,008
Regulatory asset - asset retirement obligation		**502,785**		557,239
Accumulated decrease in fair value of hedging derivatives		**2,659**		19,348
Unamortized loss on refunded and defeased debt		**166,970**		173,079
Total deferred outflows of resources	**$**	**757,674**	$	829,286
Total assets & deferred outflows of resources	**$**	**12,327,522**	$	12,146,681

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, 2024 and 2023

	2024	2023
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long-term debt	**$ 129,905**	$ 56,585
Accrued interest on long-term debt	**39,982**	38,770
Revolving credit agreement	**1,394**	1,394
Commercial paper	**172,461**	183,363
Accounts payable	**227,812**	189,501
Other current liabilities	**79,330**	126,303
Total current liabilities	**650,884**	595,916
Noncurrent liabilities		
Construction liabilities	**25,161**	4,519
Net OPEB liability	**161,232**	150,037
Net Pension liability	**279,573**	302,480
Asset retirement obligation liability	**504,198**	558,786
Total long-term debt (net of current portion)	**7,419,557**	7,129,966
Unamortized debt discounts and premiums	**542,077**	475,585
Long-term debt-net	**7,961,634**	7,605,551
Other credits and noncurrent liabilities	**111,347**	109,089
Total noncurrent liabilities	**9,043,145**	8,730,462
Total liabilities	**$ 9,694,029**	$ 9,326,378
DEFERRED INFLOWS OF RESOURCES		
Deferred inflows - pension	**$ 26,417**	$ 12,230
Deferred inflows - OPEB	**41,487**	52,698
Accumulated increase in fair value of hedging derivatives	**38,622**	54,819
Nuclear decommissioning costs	**220,145**	217,120
Regulatory Inflows - Toshiba Settlement	**224,202**	233,084
Total deferred inflows of resources	**$ 550,873**	$ 569,951
NET POSITION		
Net investment in capital assets	**$ 1,919,010**	$ 2,001,334
Restricted for debt service	**15,766**	12,182
Unrestricted	**147,844**	236,836
Total net position	**$ 2,082,620**	$ 2,250,352
Total liabilities, deferred inflows of resources & net position	**$ 12,327,522**	$ 12,146,681

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, 2024 and December 31, 2023

	2024	2023
	(Thousands)	
Operating revenues		
Sale of electricity	**$ 1,880,992**	$ 1,825,124
Sale of water	**8,791**	7,493
Other operating revenue	**27,068**	17,986
Total operating revenues	**1,916,851**	1,850,603
Operating expenses		
Electric operating expenses		
Production	**191,795**	179,981
Fuel	**597,882**	525,929
Purchased and interchanged power	**324,448**	126,693
Transmission	**55,805**	46,897
Distribution	**14,533**	14,110
Customer accounts and other	**19,976**	18,997
Administrative and general	**99,540**	79,231
Electric maintenance expenses	**176,583**	154,369
Water operating and maintenance expenses	**7,259**	5,937
Depreciation	**270,653**	272,161
Sums in lieu of taxes	**5,833**	5,223
Total operating expenses	**1,764,307**	1,429,528
Operating income	**152,544**	421,075
Nonoperating revenues (expenses)		
Interest and investment revenue	**16,691**	16,939
Net increase (decrease) in fair value of investments	**16,718**	20,209
Interest expense on long-term debt	**(322,518)**	(309,079)
U.S. Treasury subsidy on Build America Bonds	**7,752**	7,669
Interest expense on commercial paper and other	**(2,526)**	(5,966)
Regulatory amortization - net	**(38,141)**	(23,573)
Other-net	**21,168**	8,120
Total nonoperating revenues (expenses)	**(300,856)**	(285,681)
Income before transfers	**(148,312)**	135,394
Transfers		
Distribution to the State	**(19,420)**	(18,961)
Change in net position	**(167,732)**	116,433
Total net position-beginning of period	**2,250,352**	2,133,919
Total net position-ending	**$ 2,082,620**	$ 2,250,352

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

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Statements of Cash Flows - Business - Type Activities

South Carolina Public Service Authority
Years Ended December 31, 2024 and 2023

	2024	2023
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	**$ 1,887,512**	$ 1,895,931
Payments to non-fuel suppliers	**(678,562)**	(853,744)
Payments for fuel	**(562,200)**	(615,265)
Purchased power	**(295,145)**	(274,712)
Payments to employees	**(200,054)**	(198,166)
Other receipts-net	**392,815**	341,634
Net cash provided by operating activities	**544,366**	295,678
Cash flows from non-capital related financing activities		
Distribution to the State	**(19,420)**	(18,961)
Proceeds from revolving credit agreement draw	**36,000**	185,000
Proceeds from issuance of commercial paper notes	**53,100**	116,000
Repayment of commercial paper notes	**(77,409)**	(20,297)
Refunding / defeasance of long-term debt	**0**	(27,868)
Repayment of long-term debt	**(7,403)**	(10,628)
Interest paid on long-term debt	**(191,843)**	(186,656)
Interest paid on commercial paper and other	**(9,612)**	(8,023)
Other-net	**(11,459)**	(4,685)
Net cash (used in) provided by non-capital related financing activities	**(228,046)**	23,882
Cash flows from capital-related financing activities		
Repayment of revolving credit agreement draw	**0**	(600)
Proceeds from issuance of commercial paper notes	**15,624**	15,598
Repayment of commercial paper notes	**(2,217)**	(46,184)
Refunding / defeasance of long-term debt	**0**	(34,813)
Proceeds from sale of bonds	**479,587**	0
Repayment of long-term debt	**(49,182)**	(28,897)
Interest paid on long-term debt	**(152,428)**	(159,005)
Interest paid on commercial paper and other	**(4,778)**	(3,530)
Construction and betterments of utility plant	**(515,045)**	(330,926)
Other-net	**(44,890)**	(26,335)
Net cash (used in) capital-related financing activities	**(273,329)**	(614,692)
Cash flows from investing activities		
Proceeds from the sale and maturity of investment securities	**705,651**	921,004
Purchase of investment securities	**(749,510)**	(721,485)
Interest on investments	**16,343**	15,723
Net cash (used in) provided by investing activities	**(27,516)**	215,242
Net increase (decrease) in cash and cash equivalents	**15,475**	(79,890)
Cash and cash equivalents-beginning	**272,942**	352,832
Cash and cash equivalents-ending	**$ 288,417**	$ 272,942

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, 2024, and 2023

		2024		2023
Reconciliation of operating income to net cash provided by operating activities		(Thousands)		
Operating income	**$**	**152,544**	$	421,075
Adjustments to reconcile operating income to net cash provided by operating activities				
Depreciation		**270,653**		272,161
Amortization of nuclear fuel		**16,032**		16,134
Net power gains (losses) involving associated companies		**(42,372)**		(49,389)
Distributions from associated companies		**42,360**		48,648
Advances to/from associated companies		**1,004**		1,764
Changes in assets and liabilities				
Accounts receivable-net		**(30,168)**		45,207
Inventories		**24,703**		(93,001)
Prepaid expenses		**20,454**		58,801
Other deferred debits		**207,239**		(42,173)
Accounts payable		**(15,003)**		(32,292)
Other current liabilities		**(39,936)**		(187,945)
Other noncurrent liabilities		**(63,144)**		(163,312)
Net cash provided by operating activities	**$**	**544,366**	$	295,678
Composition of cash and cash equivalents				
Current				
Unrestricted cash and cash equivalents	**$**	**193,097**	$	236,702
Restricted cash and cash equivalents		**94,397**		35,904
Noncurrent				
Restricted cash and cash equivalents		**923**		336
Cash and cash equivalents at the end of the year	**$**	**288,417**	$	272,942
Noncash capital activities-Accounts Payable	**$**	**68,705**	$	15,391
Noncash capital-relating financing activities - Refunding of long-term debt	**$**	**925,165**	$	0

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, 2024, and 2023

		2024		2023
		(Thousands)		
ASSETS				
Cash and cash equivalents	**$**	**1,150**	$	2,668
Investments		**116,050**		103,351
Total assets	**$**	**117,200**	$	106,019
LIABILITIES				
Total liabilities	**$**	**0**	$	0
NET POSITION				
Restricted for other postemployment benefits (OPEB)	**$**	**117,200**	$	106,019
Total net position	**$**	**117,200**	$	106,019
Total liabilities & net position	**$**	**117,200**	$	106,019

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, 2024 and 2023

	2024	2023
	(Thousands)	
ADDITIONS		
Employer contributions	**$ 9,243**	$ 12,804
Total employer contributions	**9,243**	12,804
Investment income (loss)		
Appreciation (depreciation) in fair value of investments	**(2,429)**	253
Interest	**4,367**	3,531
Net investment income (loss)	**1,938**	3,784
Total additions	**11,181**	16,588
DEDUCTIONS		
Total deductions	**0**	0
Change in net position	**11,181**	16,588
Net position - beginning of period	**106,019**	89,431
Total net position - ending	**$ 117,200**	$ 106,019

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,	**2024**	2023
Annual average depreciation percentages	**3.0%**	3.1%

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, 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.

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 Pond A and decant pond (a non-CCR unit) and for the Winyah West Ash Pond have been approved by the South Carolina Department of Environmental Services ("SCDES"), formally known as the Department of Health and Environmental Control ("DHEC"), and closure is in progress, with regulatory deadlines of 2030. The Jefferies Ash Pond A and Winyah West Ash Pond were not subject to the 2015 CCR Rule. However, these ponds, along with the closed Grainger Generating Station Ash Pond 1, Grainger Ash Pond 2, and the Jefferies Rail Loop area, are now subject to the requirements of the EPA's new Legacy CCR rulemaking, which became effective on November 8, 2024. The Cross Bottom Ash Pond and the remaining four 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 SCDES closure regulations. Closure is in progress on all ponds and SCDES plans are being developed and implemented to facilitate closure of these remaining ponds by the CCR Rule's regulatory deadlines 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. Closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards for those units at Cross and Winyah that are subject to groundwater corrective action. Pond closure activities are expected to continue at least through 2031, and estimates of remaining costs are projected to be approximately $159.4 million between 2025 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 also do not include potential expenses associated with the Legacy Rule's requirements for CCR Management Units ("CCRMUs") that have not yet been identified. The Winyah West Ash Pond and Jefferies Rail Loop area are known CCRMUs, but additional CCRMUs may be identified at the Cross, Winyah, Jefferies, and Grainger Generating Stations during the Legacy Rule's Facility Evaluation process.

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 SCDES'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,		**2024**			2023	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 404.0**	**$ 154.8**	**$ 558.8**	$ 451.9	$ 178.6	$ 630.5
Accretion expense	**11.5**	**4.0**	**15.5**	12.8	3.3	16.1
Additions	**0**	**8.1**	**8.1**	0	0	0
Adjustments/Removals/Settlements	**0**	**(78.2)**	**(78.2)**	(60.7)	(27.1)	(87.8)
Balance as of December 31,	**$ 415.5**	**$ 88.7**	**$ 504.2**	$ 404.0	$ 154.8	$ 558.8
Regulatory Asset - ARO	**$ 415.4**	**$ 87.4**	**$ 502.8**	$ 403.8	$ 153.4	$ 557.2

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, 2024 and 2023 were $31.8 million and $22.6 million, respectively, which are included as part of electric operating expenses, and represent a cumulative amount reported to date based on the use of 27% of the total permitted capacity of the Cross Landfill Area 1B, 100% of the total permitted capacity of the Winyah Landfill Area 1, and 27% of Winyah Landfill Area 2. The Authority will recognize the remaining estimated cost of closure and post-closure care for these landfill areas of $43.9 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 2024. The landfill closure and post-closure care liabilities at December 31, 2024 and 2023 were $17.9 million and $16.5 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 ongoing basis, as needed for the life of the plant. The Authority closed 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 2024, 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 material impairments in 2024 and 2023.

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.

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, $47.0 million and $32.1 million was amortized in 2024 and 2023, respectively. The remaining balance outstanding at December 31, 2024 was $3.563 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 2024 and 2023 $8.9 million and $8.9 million, respectively was amortized. The remaining balance outstanding at December 31, 2024 was $224.2 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, in 2023 and in 2024, the Board authorized the use of regulatory accounting for the 2022 Cook Rate Freeze Exceptions and the 2023 Cook Rate Freeze Exceptions for new exceptions that were not in the previous Board approvals. On February 25, 2025, an agreement was executed by the Authority, Central and Class Counsel regarding the Exceptions Dispute (the "Exceptions Agreement" See Note 15 - Subsequent Events). As a result of this agreement, as of December 31, 2024 the Authority adjusted the balance of the Cook Settlement Exceptions Regulatory Asset to $550.0 million and recognized net expenses of $153.8 million previously deferred (See Note 5 - Cook Settlement as to Rates).

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, 2024 was $144.9 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), GRDA (Oklahoma) 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,		**2024**		2023
		(Thousands)		
TEA Investment:				
Balance as of January 1,	**$**	**28,697**	$	25,935
Reduction to power costs and increases in electric revenues		**46,156**		51,409
Less: Distributions from TEA		**42,360**		48,647
Balance as of December 31,	**$**	**32,493**	$	28,697
Due To/Due From TEA:				
Payable to	**$**	**22,862**	$	35,097
Receivable from	**$**	**2,912**	$	3,623

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, 2024, the trade guarantees are an amount not to exceed Santee Cooper's share of approximately $126.1 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,	**2024**	2023
	(Thousands)	
Deferred outflows of resources	**$ 757,674**	$ 829,286
Deferred inflows of resources	**$ 550,873**	$ 569,951

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, 2024 and 2023 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,			**2024**		2023
	Account Classification		(Millions)		
Fair Value					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**38.3**	$	32.0
Heating Oil	Regulatory Assets/ Liabilities		**(2.3)**		3.5
Changes in Fair Value					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**6.3**	$	(119.9)
Heating Oil	Regulatory Assets/ Liabilities		**(5.8)**		(26.5)
Recognized Net Gains (Losses)					
Natural Gas	Operating Expense - Fuel	**$**	**(9.5)**	$	(50.4)
Heating Oil	Operating Expense - Fuel		**0.3**		9.7
Realized But Not Recognized Net Gains (Losses)					
Natural Gas	Regulatory Assets/ Liabilities	**$**	**2.0**	$	(1.2)
Heating Oil	Regulatory Assets/ Liabilities		**(0.2)**		0.1
Notional					
			MMBTUs		
Natural Gas			**44,364**		87,314
			Gallons (000s)		
Heating Oil			**8,022**		17,220
Maturities					
Natural Gas			**Jan-2025 - Dec 2026**		Jan 2024 - Dec 2026
Heating Oil			**Jan-2025 - Dec 2025**		Jan 2024 - 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 $16.1 million in 2024 and $13.8 million in 2023.

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.

Charges to Central were also billed under the rate freeze schedules from August 2020 through December 31, 2024. Beginning in January 2025 rates to Central will be 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, Central and Class Counsel 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)*.

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 2024 and 2023 totaled approximately $19.4 million and $19.0 million, respectively.

S - New Accounting Standards –

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 101	**Compensated Absences**	The Company adopted, it did not have a material impact on financial postion, results of operations or cash flows.
Issue Date: June 2022	Effective for periods beginning after December 15, 2023	
Description:	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:	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.	

Statement No. GASB 103	**Financial Reporting Improvements**	Under review
Issue Date: April 2024	Effective for periods beginning after June 15, 2025	
Description:	This Statement continues the requirement that the basic financial statements be preceded by management's discussion and analysis (MD&A), which is presented as required supplementary information (RSI). MD&A provides an objective and easily readable analysis of the government's financial activities based on currently known facts, decisions, or conditions and presents comparisons between the current year and the prior year. This Statement requires that the information presented in MD&A be limited to the related topics discussed in five sections: (1) Overview of the Financial Statements, (2) Financial Summary, (3) Detailed Analyses, (4) Significant Capital Asset and Long-Term Financing Activity, and (5) Currently Known Facts, Decisions, or Conditions. This Statement describes unusual or infrequent items as transactions and other events that are either unusual in nature or infrequent in occurrence. Furthermore, governments are required to display the inflows and outflows related to each unusual or infrequent item separately as the last presented flow(s) of resources prior to the net change in resource flows in the government-wide, governmental fund, and proprietary fund statements of resource flows. This Statement requires that the proprietary fund statement of revenues, expenses, and changes in fund net position continue to distinguish between operating and nonoperating revenues and expenses. Operating revenues and expenses are defined as revenues and expenses other than nonoperating revenues and expenses. Nonoperating revenues and expenses are defined as (1) subsidies received and provided, (2) contributions to permanent and term endowments, (3) revenues and expenses related to financing, (4) resources from the disposal of capital assets and inventory, and (5) investment income and expenses. This Statement requires governments to present each major component unit separately in the reporting entity's statement of net position and statement of activities if it does not reduce the readability of the statements. If the readability of those statements would be reduced, combining statements of major component units should be presented after the fund financial statements. This Statement requires governments to present budgetary comparison information using a single method of communication—RSI. Governments also are required to present (1) variances between original and final budget amounts and (2) variances between final budget and actual amounts. An explanation of significant variances is required to be presented in notes to RSI.	
Statement No. GASB 104	**Disclosure of Certain Capital Assets**	Under Review
Issue Date: September 2024	Effective for fiscal years beginning after June 15, 2025	
Description:	This Statement requires certain types of capital assets to be disclosed separately in the capital assets note disclosures required by Statement 34. Lease assets recognized in accordance with Statement No. 87, Leases, and intangible right-to-use assets recognized in accordance with Statement No. 94, Public-Private and Public-Public Partnerships and Availability Payment Arrangements, should be disclosed separately by major class of underlying asset in the capital assets note disclosures. Subscription assets recognized in accordance with Statement No. 96, Subscription-Based Information Technology Arrangements, also should be separately disclosed. In addition, this Statement requires intangible assets other than those three types to be disclosed separately by major class. This Statement also requires additional disclosures for capital assets held for sale. A capital asset is a capital asset held for sale if (a) the government has decided to pursue the sale of the capital asset and (b) it is probable that the sale will be finalized within one year of the financial statement date. Governments should consider relevant factors to evaluate the likelihood of the capital asset being sold within the established time frame. This Statement requires that capital assets held for sale be evaluated each reporting period. Governments should disclose (1) the ending balance of capital assets held for sale, with separate disclosure for historical cost and accumulated depreciation by major class of asset, and (2) the carrying amount of debt for which the capital assets held for sale are pledged as collateral for each major class of asset.	

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,	**2024**	2023
	(Millions)	
CTBR regulatory asset:		
Balance	**$ 213.8**	$ 213.5
CTBR expense/(reduction to expense):		
Net Expense	**$ (0.3)**	$ 8.4

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2024 and 2023 was as follows:

	Beginning Balances	**Increases**	**Decreases**	**Ending Balances**
		Year 2024 (Thousands)		
Utility Plant [1]	**$ 9,530,569**	**$ 205,928**	**$ (57,954)**	**$ 9,678,543**
Accumulated depreciation	**(4,891,661)**	**(271,387)**	**101,416**	**(5,061,632)**
Total utility plant-net	**4,638,908**	**(65,459)**	**43,462**	**4,616,911**
Construction work in progress	**431,202**	**543,122**	**(206,458)**	**767,866**
Other Physical property-net	**25,502**	**474**	**(218)**	**25,758**
Totals	**$ 5,095,612**	**$ 478,137**	**$ (163,214)**	**$ 5,410,535**

	Beginning Balances	Increases	Decreases	Ending Balances
		Year 2023 (Thousands)		
Utility Plant [1]	$ 9,387,933	$ 184,701	$ (42,065)	$ 9,530,569
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

[1] Utility Plant includes $110 million for nuclear fuel in 2024 and $113 million in 2023.

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,	**2024**			2023		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 78,441**	**$ 8,999**	**$ 87,440**	$ 67,710	$ 32,064	$ 99,774
Debt Reduction	**8,936**	**9,978**	**18,914**	10,760	6,890	17,650
Funds from Taxable Borrowings	**17,947**	**75,538**	**93,485**	1,129	33,978	35,107
General Improvement	**4**	**0**	**4**	4	0	4
Internal Nuclear Decommissioning Fund	**252**	**85,590**	**85,842**	887	83,966	84,853
Nuclear Fuel	**18,690**	**0**	**18,690**	14,707	0	14,707
Revenue and Operating	**28,805**	**251**	**29,056**	96,098	250	96,348
Special Reserve and Other	**40,022**	**32,920**	**72,942**	45,407	21,242	66,649
Total	**$ 193,097**	**$ 213,276**	**$ 406,373**	$ 236,702	$ 178,390	$ 415,092
Current Restricted:						
Debt Service Funds	**$ 20,375**	**$ 35,372**	**$ 55,747**	$ 22,646	$ 28,307	$ 50,953
Funds from Tax-exempt Borrowings	**60,941**	**217,044**	**277,985**	10,358	209,651	220,009
Special Reserve and Other	**13,081**	**30,099**	**43,180**	2,900	26,629	29,529
Total	**$ 94,397**	**$ 282,515**	**$ 376,912**	$ 35,904	$ 264,587	$ 300,491
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 923**	**$ 132,115**	**$ 133,038**	$ 336	$ 130,709	$ 131,045
Total	**$ 923**	**$ 132,115**	**$ 133,038**	$ 336	$ 130,709	$ 131,045
TOTAL FUNDS	**$ 288,417**	**$ 627,906**	**$ 916,323**	$ 272,942	$ 573,686	$ 846,628
Cash and investments as of December 31, consisted of the following:						
Cash/Deposits			**$ 20,576**			$ 22,350
Investments			**895,747**			824,278
Total cash and investments			**$ 916,323**			$ 846,628

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,	**2024**	2023
Total Portfolio	(Billions)	
Total investments	**$ 0.9**	$ 0.8
Purchases	**26.6**	26.9
Sales	**26.5**	27.2
Nuclear Decommissioning Portfolios	(Millions)	
Total investments	**$ 218.0**	$ 215.6
Purchases	**105.0**	242.0
Sales	**100.4**	235.7
Unrealized holding gain/(loss)	**(2.2)**	6.1
Repurchase Agreements[1]	(Millions)	
Balance at December 31	**$ 110.0**	$ 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, 2024 and 2023, 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, 2024 and 2023, 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, 2024 and 2023, 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, 2024 and 2023 were as follows:

Security Type / Issuer	Fair Value 2024	Fair Value 2023
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 127,567**	$ 119,744
Federal Farm Credit Bank	**106,410**	97,236
Federal Home Loan Mortgage Corp	**Less than 5%**	58,018

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, 2024 and 2023:

		Investment Maturities as of December 31, 2024			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Collateralized Deposits	**$ 137,086**	**$ 136,835**	**$ 251**	**$ 0**	**$ 0**
Repurchase Agreements	**110,000**	**110,000**	**0**	**0**	**0**
Federal Agency Discount Notes	**40,550**	**40,550**	**0**	**0**	**0**
Federal Agency Securities	**227,861**	**34,644**	**69,724**	**62,634**	**60,859**
US Treasury Bills, Notes and Strips	**380,250**	**352,958**	**15,346**	**0**	**11,946**
	$ 895,747	**$ 674,987**	**$ 85,321**	**$ 62,634**	**$ 72,805**

		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

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 internal Nuclear Decommissioning Fund also holds $5.0 million par in government agency zero coupon securities maturing on 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, 2024 and 2023:

2024	**Total**	**Level 1**	**Level 2**	**Level 3**
		(Thousands)		
Collateralized Deposits	**$ 137,086**	**$ 0**	**$ 137,086**	**$ 0**
Repurchase Agreements	**110,000**	**0**	**110,000**	**0**
Federal Agency Discount Notes	**40,550**	**0**	**40,550**	**0**
Federal Agency Securities	**227,861**	**0**	**227,861**	**0**
US Treasury Bills, Notes and Strips	**380,250**	**0**	**380,250**	**0**
	$ 895,747	**$ 0**	**$ 895,747**	**$ 0**

2023	Total	Level 1	Level 2	Level 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

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, 2024 and 2023, 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, 2024 and 2023, 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, 2024 and 2023, 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, 2024 and 2023 were as follows:

Security Type / Issuer	Fair Value 2024	Fair Value 2023
		(Thousands)
Federal Agency Fixed Income Securities		
Federal Home Loan Bank	**$ 21,641**	$ 23,438
Federal Farm Credit Bank	**36,250**	33,498
Federal Home Loan Mortgage Corp	**14,665**	17,036

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 following table shows the distribution of the OPEB Trust's investments by maturity as of December 31, 2024 and 2023:

		Investment Maturities as of December 31, 2024			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
			(Thousands)		
Federal Agency Securities	**79,041**	**0**	**1,681**	**15,372**	**61,988**
Government Securities	**38,235**	**1,150**	**9**	**1,620**	**35,456**
	$ 117,276	**$ 1,150**	**$ 1,690**	**$ 16,992**	**$ 97,444**

		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

Risk Type	Exposure
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, 2024 and 2023:

		Level		
2024	**Total**	**1**	**2**	**3**
		(Thousands)		
Federal Agency Securities	**79,041**	**0**	**79,041**	**0**
Government Securities	**38,235**	**0**	**38,235**	**0**
	$ 117,276	**$ 0**	**$ 117,276**	**$ 0**

		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

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Note 5 – Cook Settlement

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 Authority filed its 2023 Annual Compliance Report covering the period from January 1, 2023 through December 31, 2023 (the “2023 Reporting Period”) on April 30, 2024. The 2023 Annual Compliance Report identified nine situations falling within four categories of costs and expenses occurring during the 2023 Reporting Period that qualify as Cook Rate Freeze Exceptions, including (i) $63,643,742.18 resulting from various changes in law, (ii) $141,289,189.07 resulting from fires, (iii) $995,720.45 resulting from a named storm, and (iv) $260,612.20 resulting from an act of God and flood.

The following table illustrates the impact on expenses (decreases)/increases in each year due to recording the Regulatory Asset for Cook Exceptions in 2024 and 2023:

Years Ending December 31:	**2024**	2023
	(Thousands)	
Operating expenses	**$ 92,617**	$ (243,247)
Interest on long-term debt	**(12,275)**	(17,297)
Interest on commercial paper	**(5,232)**	(5,961)
Increase (decrease) to expenses	**$ 75,110**	$ (266,505)

The amounts recorded in 2024 include amounts to reduce prior regulatory asset amounts that were impacted by the recent settlement reached in the “Exceptions Agreement.” See Note 15- Subsequent Events for further discussion.

The following reflects the Cook Deferred Expenses recorded as the Cook Exceptions Regulatory Asset as of December 31, 2024:

Year Ending December 31:	**2024**	**Reductions**	**Additions**	2023
		(Thousands)		
Load Exception – Certain deviations in Central’s actual loads	**$ 0**	**$ (13,170)**	**$ 0**	$ 13,170
Load Exception Interest – Certain deviation in Central’s actual loads	**0**	**(8,398)**	**0**	8,398
Interest	**49,163**	**(16,693)**	**42,598**	23,258
Foresight Local Mine Fire – Subsequent change in law that required the mine to stay closed	**482,860**	**0**	**27,309**	455,551
Change in Law	**17,977**	**(90,368)**	**8,023**	100,322
VCS 1 Fire	**0**	**(4,824)**	**0**	4,824
Named Storm Events – Hurricane Isaias, Idalia, Ian and Tropical Storm Elsa, Jasper, and Izzy	**0**	**(2,805)**	**460**	2,345
Winter Storm - Elliott	**0**	**(17,242)**	**0**	17,242
WGS clean up	**0**	**(261)**	**261**	0
Total Regulatory Asset	**$ 550,000**	**$ (153,761)**	**$ 78,651**	$ 625,110

Note 6 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2024 and 2023 consisted of the following:

	2024	2023	Interest Rate(s) [1]	Call Price [2]
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2009 Taxable Series C	**1,000**	1,305	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**	159,837	4.122-4.551	P&I Plus Make-Whole Premium
2013 Tax-exempt Series A	**0**	107,560	5.000-5.500	100
2013 Tax-exempt Refunding Series B	**0**	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	**0**	275,730	5.000-5.500	100
2014 Tax-exempt Series A	**0**	294,970	5.000-5.500	100
2014 Tax-exempt Refunding Series B	**0**	22,380	5.000	100
2014 Tax-exempt Refunding Series C	**325,405**	351,625	3.000-5.000	100
2014 Taxable Refunding Series D	**16,890**	16,890	3.406-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	**344,840**	353,110	3.000-5.000	100
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	**45,975**	48,220	3.000-5.000	100
2019 Tax-exempt Refunding Series A [4]	**117,050**	124,795	VRD	100
2020 Tax-exempt Refunding Series A	**333,455**	333,540	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	**143,415**	144,225	4.000-5.000	100
2021 Tax-exempt Series B	**270,730**	280,170	4.000-5.000	100
2022 Tax-exempt Refunding Series A	**928,130**	929,595	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**	34,470	5.000-5.500	100
2022 Taxable Refunding Series D	**127,735**	127,735	5.913-6.436	P&I Plus Make-Whole Premium
2022 Tax-exempt Series E	**386,370**	386,370	5.000-5.750	100
2022 Taxable Series F	**59,505**	59,505	5.913-6.447	P&I Plus Make-Whole Premium
2024 Tax-exempt Series A	**372,000**	0	5.000-5.500	100
2024 Tax-exempt Refunding Series B	**865,055**	0	4.125-5.000	100
2024 Taxable Series C	**73,000**	0	4.983-5.583	P&I Plus Make-Whole Premium
Total Revenue Obligations	**7,112,390**	6,784,085		
Direct Placement Long-Term Revolving Credit Agreement: (matures through 2036)	**437,072**	402,466	N/A	N/A
Less: Current Portion - Long-term Debt	**129,905**	56,585		
Total Long-term Debt - (Net of current portion)	**$7,419,557**	$7,129,966		

[1] Interest Rates apply only to bonds outstanding as of December 31, 2024.

[2] Call Price may only apply to certain maturities outstanding at December 31, 2024.

[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, 2024 and 2023 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 2024 (Thousands)				
Revenue Obligations[1]	**$ 6,784,085**	**$ 1,310,055**	**$ (981,750)**	**$ 7,112,390**	**$ 129,905**	**$ 6,982,485**	**$ 542,077**	**$ 7,524,562**
Direct Placement Long-Term Revolving Credit Agreement	**403,860**	**34,606**	**0**	**438,466**	**1,394**	**437,072**	**0**	**437,072**
Totals	**$ 7,187,945**	**$ 1,344,661**	**$ (981,750)**	**$ 7,550,856**	**$ 131,299**	**$ 7,419,557**	**$ 542,077**	**$ 7,961,634**
				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	1394	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

(1) 2024 Tax-Exempt Improvement Series A, Tax-Exempt Refunding Series B and Taxable Improvement Series C closed on July 30, 2024

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 [1]	Total Principal	Total Interest [2]	Total
Year Ending December 31,			(Thousands)		
2025	$ 129,905	$ 1,394	$ 131,299	$ 361,344	$ 492,643
2026	158,792	340,814	499,606	336,233	835,839
2027	158,496	82,854	241,350	327,774	569,124
2028	183,475	1,274	184,749	320,915	505,664
2029	177,726	1,274	179,000	312,435	491,435
2030-2033	875,971	5,096	881,067	1,158,726	2,039,793
2034-2038	1,200,440	5,760	1,206,200	1,208,019	2,414,219
2039-2043	1,185,651	0	1,185,651	923,178	2,108,829
2044-2048	1,329,984	0	1,329,984	611,943	1,941,927
2049-2053	1,353,981	0	1,353,981	275,362	1,629,343
2054-2056	357,969	0	357,969	25,894	383,863
Total	$ 7,112,390	$ 438,466	$ 7,550,856	$ 5,861,823	$ 13,412,679

(1) This table does not reflect refinancing or amortization of the RCA's issued to fund the Cook Exceptions as of December 31, 2025.

(2) 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, 2024 are as follows:

Refunding Description	Outstanding	Original Loss	Unamortized Loss
	(Thousands)		
Total	$ 0	$ 266,321	$ 166,970

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

There were no defeased debt, cash placed in escrow, or defeased debt outstanding at December 31, 2024.

Bond Market Transactions

Bond market transactions for the year ended December 31, 2024 were as follows:

Revenue Obligations, 2024 Tax-Exempt Improvement Series A, Tax-Exempt Refunding Series B and Taxable Improvement Series C	**Par Amount: $1,310,055,000**	**Date Authorized: July 24, 2024**
Summary: - Issued on July 30, 2024 at an all-in true interest rate of 4.551 percent, Matures December 1, 2054		
The refunding produced $101.1 million in net present value savings and an economic gain of $2.0 million		

Debt Covenant Compliance

As of December 31, 2024, and 2023, management believes the Authority was in compliance with all Financial 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,	**2024**	2023
Outstanding Revenue Obligations	**$7.1 Billion**	$6.8 Billion
Estimated remaining interest payments	**$5.8 Billion**	$5.8 Billion
Issuance years (inclusive)	**2009 through 2024**	2009 through 2022
Maturity years (inclusive)	**2025 through 2056**	2024 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, 2024, 9% of the Authority's aggregate debt outstanding was variable rate (this includes $117 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,	**2024**	2023
Commercial paper outstanding (000's)	**$ 172,461**	$ 183,363
Effective interest rate (at December 31)	**4.66%**	5.46%
Average annual amount outstanding (000's)	**$ 200,505**	$ 156,256
Average maturity	**67 Days**	50 Days
Average annual effective interest rate	**4.33%**	5.25%

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,	**2024**			2023		
	Capacity	**Unused Capacity**	**Expiration**	Capacity	Unused Capacity	Expiration
			(Thousands)			
Commercial Paper Reimbursement Agreements backed by Letters of Credit:						
	$ 200,000	**$ 189,754**	**September 17, 2027**	$ 100,000	$ 96,622	September 6, 2024
	200,000	**37,785**	**September 15, 2028**	200,000	20,015	February 28, 2025
Revolving Credit Agreements:						
	100,000	**11,900**	**March 25, 2027**	100,000	11,900	March 25, 2025
	250,000	**58,400**	**March 20, 2026**	200,000	34,400	March 20, 2026
	250,000	**91,234**	**March 31, 2026**	250,000	99,840	March 31, 2026
	200,000	**200,000**	**June 30, 2026**	200,000	200,000	June 28, 2024
Total	**$ 1,200,000**	**$ 589,073**		$ 1,050,000	$ 462,777	

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 extended the operating license for Summer Nuclear Unit 1 an additional twenty years to August 6, 2042. On August 17, 2023, Dominion submitted a Subsequent License Renewal application to the NRC on behalf of itself and the Authority to extend the operating license for Summer Nuclear Unit 1 from August 2042 to August 2062. The renewal process is expected to be completed by August 2025.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,	**2024**	2023
	(Millions)	
Plant balances before depreciation	**$ 821.5**	$ 805.8
Accumulated depreciation	**338.4**	331.0
Operation & maintenance expense	**89.1**	91.2

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.

Dominion contracted with HOLTEC International, The Shaw Group, Inc. ("Shaw") and Westinghouse to build a licensed Independent Spent Fuel Storage Installation ("ISFSI"), which was completed and commenced receiving fuel in 2016. Because of the DOE's failure to meet its obligation to dispose of spent fuel, Dominion and the Authority are being reimbursed by DOE for a portion of ISFSI project costs. The DOE reimbursements to date equal approximately 85% of the total project costs.

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. 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 $218.0 million (adjusted to market) at December 31, 2024, 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.

The following table summarizes the nuclear-related regulatory items:

Regulatory Item	Classification	Original Amount	2018 - 2024 Amortization	2018 - 2024 Changes	2024 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($608.3 million)	($40.2 million)	$ 3.563 billion
Nuclear post-suspension interest	Asset	$ 37.1 million	$ (439,000)		$ 36.7 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($687.8 million)	$13.8 million	$ 224.2 million

Sales of Summer Nuclear Units 2 and 3 Assets. Since 2018, the Authority has sold certain equipment and commodities located at the Summer Nuclear Station to third parties. As of December 31, 2024, $107.5 million of such materials have been sold. The Authority continues to work with Westinghouse to market and identify potential buyers of nuclear assets located at the Summer Nuclear Station, which may include a significant number of available assets sold to a single buyer. Authority approval is required to proceed with any such sale. The Authority expects to use the net proceeds received from the sale of nuclear-related equipment in its overall financial plan.

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 2024, revenues pursuant to the Coordination Agreement were 60% of total sales of electricity, consistent with 58% in 2023.

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 2013 the Central and Authority Boards approved an Amendment to the Coordination Agreement. As part of this, Central agreed to waive 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%. Five contracts with terms ranging from 15-20 years were awarded, totaling 425 MW. As of December 2024, only two of these contracts, totaling 200 MW, are expected to reach commercial operation.

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, 2024. 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)	
2025	$ 244,000	$ 234,000
2026	246,000	236,000
2027	134,000	129,000
2028	136,000	130,000
2029	73,000	73,000
2030	75,000	75,000
Total	$ 908,000	$ 877,000

[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, 2024:

Contracts with Power Receipt and Payment Obligations [1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	1 Years	14.7
2	2013	19 Years	393.4
1	2013	9 Years	4.1
1	2021	1 Years	5.1
1	2023	3 Years	14.4
1	2023	3 Years	15.3
1	2023	4 Years	11.2
1	2024	4 Years	16.2
1	2024	4 Years	63.8
1	2025	4 Years	294.3

[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 Dominion Energy of South Carolina and Duke Energy. 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 2025 and the total transmission obligations for 2026-2035. The wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations

	2025	2026-2035
	(Thousands)	
Other Customers	$ 6,572	$ 76,681
Total	$ 6,572	$ 76,681

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 2025 and the total transmission obligations for 2026-2029 based on projected transmission rates.

Transmission Purchase Obligations

	2025	2026-2029
	(Thousands)	
Duke	$ 7,561	$ 37,153
SOCO	$ 22,726	$ 97,722
Total	$ 30,287	$ 134,875

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. As of December 2024, only two of these contracts, totaling 200 MW, are expected to reach commercial operation.

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, 2024, these contracts total approximately $99.5 million over the next 9 years.

The Authority's Executive Energy Management Committee ("EEMC") approved a new product called Prepaid Natural Gas ("PNG") on September 19, 2024. By partnering with other tax-exempt municipal entities, through a Joint Action

Agency who issues bonds, the Authority can contract with a supplier for delivery of must-take PNG at a discount to the daily market prices as long as the natural gas is being used for our Qualified Use customers (retail load). A NAESB agreement with a Joint Action Agency is required to execute any specific transactions which can be short-term or long-term (30-year terms have 5-to-7-year re-pricing periods and temporary and permanent remedies to exit the transaction). The Authority has entered into a short-term transaction for November 2024 through March 2025 and a long-term transaction dated December 18, 2024 for the 30-years beginning April 1, 2025. The long-term transaction's initial pricing period of 7 years will provide a $0.52 discount on the basis variable priced monthly at Inside FERC index. The cost of commodity and delivery variables remain open to the market; however, traditional financial hedging tools can be used to secure those exposures.

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 $25.5 million, including escalation.

The Authority has two Service Agreements in place with Transcontinental Gas Pipeline Corporation ("Transco") to supply natural gas for both its Rainey and Cherokee Generating Stations. The first agreement, on the SouthCoast Expansion, was effective November 1, 2000, and is for 80,000 dekatherms per day of firm capacity and extends through November 1, 2031 with a renewal option. The second agreement, enacted via a Precedent Agreement was signed on January 19, 2024, and is on the Southeast Supply Enhancement; it is also for 80,000 dekatherms per day of firm capacity and it has an expected effective date in 4th quarter 2027 and extends 20 years with a renewal option. The Authority works with Transco, in coordination with The Energy Authority, to determine 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 wallboard 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 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, when available, from Cameron Ag Products, LLC ("Cam Ag"), 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 Heidelberg Materials ("Heidelberg"), formally known as The SEFA Group, Inc. ("SEFA"). Pursuant to this Agreement, the Authority supplies dry fly ash and/or ponded ash from the Winyah Station to Heidelberg 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 2024. Policies are subject to deductibles ranging from $2,500 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 2024, 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, 2024. In addition, there have been no third-party claims regarding environmental damages for 2024 or 2023.

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,		**2024**		2023
		(Thousands)		
Unpaid claims and claim expense at beginning of year	**$**	**2,737**	$	2,684
Incurred claims and claim adjustment expenses:				
Add: Provision for current year events		**165**		1,066
Less: Payments for current and prior years		**596**		1,013
Total unpaid claims and claim expenses at end of year	**$**	**2,306**	$	2,737

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 $3.7 million for the primary policy and $1.1 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, 2024.

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 track greenhouse gas regulations and legislation and assess potential impacts to its operations. The latest rulemaking occurred on May 9, 2024, when the EPA published a final rule establishing various guidelines for greenhouse gas (“GHG”) emissions from existing fossil fuel-fired steam electric generating units (“EGUs”). For existing coal-fired steam EGUs, the EPA determined that carbon capture and sequestration technology ("CCS") with a 90% capture rate is the best system of emission reduction (“BSER”); affected EGUs must comply with this requirement on or prior to January 1, 2032. If a coal-fired steam EGU will cease operations by January 1, 2039, then its BSER is to co-fire with natural gas at a level of 40% of the unit’s annual heat input; the compliance deadline for those EGUs is January 1, 2030. If a coal-fired steam EGU will permanently shut down by January 1, 2032, it is exempt from these requirements. The final rule became effective on July 8, 2024. The Authority is currently analyzing the final rule to assess potential impacts to its affected EGUs.

The EPA’s May 9, 2024, final rule also established NSPS for GHG emissions from new and reconstructed fossil fuel-fired EGUs. Under the rule, the EPA categorized combustion turbines as either base load, intermediate load, or low load. For base load turbines, the BSER is: (i) highly effective generation (based on the emissions of best performing units); and (ii) CCS technology with a 90% capture rate. The CCS requirement has a compliance deadline of January 1, 2032. Intermediate load facilities must comply with interim emission standards based on the efficient design and operation of combined cycle turbines. For low load facilities, turbines are subject to emission standards based on the use of low emitting fuels. Under the final rule, the EPA eliminated greenhouse gas emissions guidelines for modified and existing gas-fired power plants. GHG emissions from existing gas-fired power plants will be promulgated under a separate future rulemaking. The final rule became effective on July 8, 2024. Litigation is pending for both of these new final GHG rules. Additionally, the new incoming Administration has stated that it intends to repeal and replace these rules. Therefore, impacts to the Authority are likely to change.

On May 7, 2024, the EPA published its final rule updating its Mercury Air Toxics Standards. The rule sets new limits on filterable particulate matter for coal- and lignite-fired power plants and requires that all coal- and oil-fired EGUs use continuous monitoring systems for particulate matter to demonstrate compliance with the new standards. The initial capital investment in new monitoring systems is around $2 million. The rule also strengths mercury emission standards for existing lignite-fired power plants by lowering the concentration limit of mercury in emissions so that it is aligned with the mercury standard that other coal-fired power plants. Numerous states filed legal challenge to the rule on May 8, 2024. On August 6, 2024, the D.C. Circuit Court denied the stay petition for the rule. Subsequently, on October 4, 2024, the U.S. Supreme Court also denied the stay petition for the rule. Litigation in the D.C. Circuit Court is still pending. At this time, the impacts of the tighter emission standard in the rule cannot be assessed but potential impacts are currently being analyzed and may be material should the changes to the rule stand.

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. SCDES 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, in 2021 the EPA announced its intention to implement a national program to evaluate and regulate a category of organic contaminants known as per- and poly-fluoroalkyl substances (“PFAS”). On April 26, 2024, the EPA published the final rule for the National Primary Drinking Water Regulation (NPDWR) to regulate six PFAS under the Safe Drinking Water Act. The rule establishes legally enforceable maximum contaminant levels (MCLs) and health-based, non-enforceable Maximum Contaminant Level Goals (MCLGs) for these PFAS. Public water systems must monitor for these PFAS, with three years to complete initial monitoring (required by 2027), followed by ongoing compliance monitoring. Water systems must also provide the public with information on the levels of PFAS in their drinking water beginning in the year 2027. Public water systems will have five years (required by 2029) to implement solutions to reduce these PFAS if monitoring shows that drinking water levels exceed these MCLs. All public water systems must comply with the MCLs by April 2029. The final rule went into effect on June 25, 2024, and applies to community water systems and non-transient, non-community water systems. This would include the Lake Marion Regional Water System, Lake Moultrie Regional Water System, and Cross Generating Station’s potable water system. These systems will require initial monitoring, compliance monitoring, and potential treatment technologies. The Authority is evaluating the range of costs and treatment options required under the final rule.

In addition, the EPA's Revised Lead and Copper Rule 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 they have a limited transmission system that 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. Cross Generating Station is required to conduct an inventory of on-site drinking water piping. On November 30, 2023, the EPA announced the proposed Lead and Copper Rule Improvements. The proposed rule would require most water systems to replace lead services lines within 10 years, require water systems to regularly update lead pipe inventories and create a publicly available replacement plan, change tap sampling protocols, lower the lead action level to 10 µg/L, and require water systems to provide filters when they have multiple exceedances of the lead action level. The Authority is continuing to evaluate impacts from this proposed rule.

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. SCDES 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 SCDES. 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. This rule implemented 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. The Authority is currently implementing requirements set forth in the 2020 ELG rule. In accordance with these guidelines, the Authority is constructing physical chemical and biological treatment facilities at both the Cross and Winyah Generating Stations for flue gas desulfurization wastewater at a cost of $150 million dollars at each facility. This new treatment equipment must be operational by the end of 2025 per the 2020 rule.

The 2020 ELG FGD limits were included through a compliance schedule in the Cross NPDES Permit effective March 1, 2024. The Winyah NPDES permit was issued in May 2024 but was appealed by environmental groups, so it is not in effect and pending an appeals court review. These permits contain schedules for implementation of FGD wastewater treatment at Cross and Winyah. The ability to switch to other compliance strategies for FGD wastewater was also included. The Authority submitted a notification to SCDES in October 2024 that Cross and Winyah intend to comply with the generally applicable effluent guidelines and accept the limitations in the permits beginning on December 31, 2025. The voluntary incentives program Notice of Planned Participation ("NOPP") will not be activated for either facility.

On July 8, 2024, the EPA rule revising technology-based ELGs of the steam electric (coal generating) power generating point source category went into effect. This final rule requires there be no discharge of FGD wastewater effective as soon as possible and no later than December 31, 2029. Litigation is ongoing from numerous industry groups and states regarding the new ELGs. Compliance with the 2024 rule is estimated to cost an additional $250 million dollars at Cross and $250 million at Winyah.

On June 9, 2021, the Army Corps of Engineers and the 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, the 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.

On March 14, 2024, the EPA finalized a rule requiring certain facilities to develop facility response plans for a worst-case discharge of CWA hazardous substances, or threat of such a discharge. The rule went into effect on May 28, 2024. Regulated facilities are required to submit response plans to the EPA within 36 months after the effective date of the rule. A worst-case discharge is the largest foreseeable discharge in adverse weather conditions, including extreme weather conditions due to climate change. Facilities subject to the rule are required to prepare response plans in the event of worst-case discharges, or threat of such discharges, and submit them to the EPA. The CWA hazardous substance FRP requirements apply to facilities that have a maximum onsite quantity of any CWA hazardous substance that meets or exceeds 1,000 times the Reportable Quantity (see 40 CFR 117.3); and are within 0.5-mile of navigable water or a conveyance to navigable water; and meet one or more of the substantial harm criteria listed in the rule. The Authority has determined that this will impact our generating stations and drinking water facilities and is reviewing compliance options.

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. SCDES 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 CCRs, are exempt from hazardous waste regulation under 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. Not all of the Authority's surface impoundments are subject to the 2015 CCR Rule. The impoundments subject to the 2015 CCR Rule are located at the Cross and Winyah Generating Stations. These CCR impoundments are closing, and as of the April 11, 2021 CCR rule deadline, all of the Authority's impoundments that are subject to the 2015 CCR Rule are no longer receiving any CCR or non-CCR waste streams.

On May 8, 2024, the EPA published a rule amending its CCR regulations for legacy CCR surface impoundments and CCR management units at active CCR facilities and at inactive CCR facilities with a legacy CCR surface impoundment. This "CCR Legacy Rule" became effective on November 8, 2024. Under the rule, the EPA established standards for legacy CCR impoundments to comply with the same regulations that apply to inactive CCR impoundments at active power plants, except for the location restrictions and the liner design criteria, with tailored compliance deadlines. This affects Jefferies Generating Station Ash Pond A. The EPA established a more limited set of requirements, primarily post-closure care, groundwater monitoring, and corrective action, if necessary, for ponds that have already completed closure under state oversight. This affects the Grainger Generating Station Ash Pond 1 and Ash Pond 2. The rule also requires a two-part Facility Evaluation process and public report to determine whether the facility has any CCR management units ("CCRMUs") containing one ton or more of CCR. This will require evaluations at the Cross, Winyah, Jefferies, and Grainger Generating Stations. CCRMUs containing 1,000 tons or more of CCR must then comply with groundwater monitoring, corrective action, closure, and post-closure care requirements. The Winyah West Ash Pond and Jefferies Rail Loop area are known CCRMUs; however, until the Facility Evaluation process is complete, it is unknown how many additional CCRMUs may become subject to this rule. This rulemaking also established 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.

The EPA has also announced their intentions to create another EPA rulemaking in the near future. If implemented, the Federal CCR Permit Program will set forth procedures to obtain federal CCR permits that will then supersede the existing federal regulations and the self-implementing scheme. This will apply to facilities in states that do not have an approved CCR program, which currently includes South Carolina. The CCR regulations and the EPA's interpretation of them have changed frequently, and the new rules and recent changes in interpretations are being litigated. Additionally, the EPA has been utilizing its enforcement authority and has found many instances of non-compliance at other utilities according to these changes in interpretations. 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 A and decant pond (a non-CCR unit) and for the Winyah West Ash Pond have been approved by SCDES and closure is in progress, with regulatory deadlines of 2030. As noted above, Jefferies Ash Pond A and Winyah West Ash Pond are subject to the requirements of the Legacy CCR rulemaking. The Cross Bottom Ash Pond and the remaining four 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 SCDES closure regulations. Closure is in progress on all ponds and SCDES plans are being developed and implemented to facilitate closure of these remaining ponds by the CCR Rule's regulatory deadlines 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. Closure by removal is the selected closure strategy and monitored natural attenuation is the selected groundwater remedy so that it meets groundwater protection standards for those units at Cross and Winyah that are subject to groundwater corrective action. Pond closure activities are expected to continue at least through 2031 and estimates of remaining costs are projected to be approximately $159.4 million between 2025 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.

The Authority's asset retirement obligation liabilities for ash ponds recorded for the years ended December 31, 2024 and 2023 were $88.7 million and $154.8 million, respectively.

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 SCDES 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. SCDES informed the Authority that SCDES 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, SCDES requested a Tier II assessment SSWP for additional soil and groundwater sampling. The Tier II results were submitted to SCDES on September 14, 2021. Subsequent activity resulted in SCDES 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 SCDES 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, SCDES began working with the lessee to get the contamination addressed on this site, identified as Site ID #-01935. SCDES 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 SCDES 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 SCDES-approved work plans. On March 17, 2021, SCDES issued a directive to Packs Landing Marina for a SSWP to conduct additional testing due to creosote found at the site. The Authority then entered into a Responsible Party Voluntary Cleanup Contract ("VCC") with SCDES on March 18, 2022. The VCC addresses the Authority's and SCDES's cooperative plan for remediation of the creosote on the property. The Authority submitted its Work Plan pursuant to the VCC process in July 2022 and SCDES approved it in August 2022. In June 2023, the first Remedial Assessment Report, which indicated shallow impacted soils that could be excavated, was submitted to SCDES and approved in July 2024. A Removal Work Plan is currently being developed. The hydrocarbon contamination is not addressed in the creosote VCC or Removal Work Plan.

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. Various studies intended to inform future management of diadromous fish species at the project, including the endangered shortnose sturgeon and Atlantic sturgeon, were initiated in 2024 in close coordination with the South Carolina Department of Natural Resources, United States Fish & Wildlife Service, National Marine Fisheries Service, and the United States Army Corps of Engineers. 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 $950,000 in capital assets for the FERC Hydroelectric license through December 31, 2024.

Legal Matters - Other than those described 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. The Authority is involved in numerous actions arising from the ordinary course of its business and is defending pending claims, including the actions described below. Claims may be settled or decided by a judge, jury, or arbitrator and may be subject to appeal. The Authority is unable to predict the outcome of the pending matters described below or predict additional claims which may arise. 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.

Pending Litigation

(a) Net Plant Dispute by Central

In 2019, following an annual audit of the Authority's records as permitted under the Central Agreement, Central took issue with the Authority's treatment of the Summer Nuclear Units 2 and 3 associated regulatory asset for purposes of allocating certain costs, including debt service and Capital Improvement Fund payments, 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 $70 million for fiscal years 2017, 2018, and 2019 and for the period January – July 2020 and a reduction of future contributions from Central in an undetermined amount. On February 12, 2025, Central and the Authority agreed to resolve the matter and executed a Capital Cost Allocation Settlement Agreement (the "CCA Agreement"). The CCA Agreement is based on an agreed-upon methodology that, among other things, continues to include the Summer Nuclear Units 2 and 3 associated regulatory asset for purposes of determining the allocation of certain costs, including debt service, and excludes the Summer Units 2 and 3 associated regulatory asset for purposes of allocating certain other costs. The CCA Agreement is not expected to have an impact on the Authority's total revenues from all customers during this same period.

(b) Cook Settlement Agreement Disputes

Cook was a class action lawsuit filed in August 2017 relating to the Authority's decision to suspend construction of V.C. Summer Nuclear Units 2 and 3 in 2017 (the "Cook Case"). In March 2020, the parties entered a settlement agreement (the "Cook Settlement Agreement) which provides a Common Benefit Fund for class members and provides for a Rate Freeze (described below). As described below, disputes have been raised regarding compliance with certain provisions of the Cook Settlement Agreement.

Rate Freeze and Rate Freeze Exceptions

Pursuant to the terms of the Cook Settlement Agreement, the Authority agreed to hold its rates consistent with rates projected in the Authority's 2019 Reform Plan beginning in August of 2020 (the "Rate Freeze") and (i) for the customers other than Central Electric Power Cooperative, Inc. ("Central") whose rates are subject to the Rate Freeze effective through all bills rendered on or before January 15, 2025, and (ii) for Central, through service rendered on or before December 31, 2024; the "Rate Freeze Period" refers to these timeframes.

The Cook Settlement Agreement authorizes the Authority to defer certain just and reasonable costs and expenses incurred during the Rate Freeze Period directly resulting from the occurrence of one or more enumerated exceptions ("Cook Rate Freeze Exceptions") and collect such amounts after the Rate Freeze Period. These circumstances include but are not limited to: changes in law (not initiated by the Authority), named storms, acts of God, significant cyber security attacks, and deviations in Central's load. The Cook Rate Freeze Exceptions must be identified and included in the Authority's Annual Cook Compliance Reports, filed with the by April 30 of each year (the "Annual Cook Compliance Reports"). In its 2020 and 2021 Annual Compliance Reports (defined below), the Authority identified Cook Rate Freeze Exceptions totaling $90.7 million. See "Annual Cook Compliance Reports" below for additional information.

On June 27, 2022, the Board of Directors of the Authority authorized the use of regulatory accounting for the Cook Rate Freeze Exceptions included in the Authority's 2020 and 2021 Annual Compliance Reports described below, including any future adjustments to those amounts, allowing the Authority to create a regulatory asset and defer expenses of those exceptions to the balance sheet. Creating this regulatory asset allows the Authority to recognize these expenses over the period it expects to recover them in rates, after the Rate Freeze Period.

Annual Cook Compliance Reports

2020 Annual Compliance Report. The Cook Settlement Agreement requires the Authority file an annual report by April 30th of each year demonstrating compliance with certain terms of the Agreement and listing any Cook Rate Freeze Exceptions eligible for collection after the Rate Freeze Period. On April 30, 2021, the Authority filed its first report (the "2020 Annual Compliance Report") covering the period from August 1, 2020 through December 31, 2020 (the "2020 Reporting Period"). The 2020 Annual Compliance Report identified three categories of costs and expenses occurring during the 2020 Reporting Period that qualify as Rate Freeze Exceptions, including (1) $5.2 million resulting from a change in law due to the COVID-19 pandemic; (2) $1.2 million resulting from named storm Hurricane Isaias; and (3) $13.3 million attributable to Central Load Deviations (collectively, the "2020 Cook Rate Freeze Exceptions").

As allowed by the Agreement, on June 9, 2021, Central filed a Request for the Appointment of an independent auditor to review the Authority's compliance as to three transactions: (1) using funds specifically allocated for capital projects to retire a scheduled balloon payment in 2023 while borrowing new money to fund existing capital project needs, (2) restructuring existing debt, and (3) using funds on hand to pay the first $65 million installment to the Common Benefit Fund. On September 10, 2021, the Court of Common Pleas for the Thirteenth Judicial Circuit (the "Court") deferred any judicial action on Central's request.

2021 Annual Compliance Report. The Authority filed its 2021 Annual Compliance Report covering the period from January 1, 2021 through December 31, 2021 (the "2021 Reporting Period") on April 29, 2022, demonstrating the Authority's compliance with the Cook Settlement Agreement (the "2021 Annual Compliance Report" and, together with the 2020 Annual Compliance Report, the "2020 and 2021 Annual Compliance Reports"). The 2021 Annual Compliance Report identified eight exceptions falling within four categories of Rate Freeze Exceptions, which the Authority could collect after the Rate Freeze Period, including: (1) $11.9 million resulting from various changes in law; (2) $175 thousand resulting from named Tropical Storm Elsa; (3) $43.4 million resulting from the fire and subsequent mine closure due to a change in law ($37.8 million) and the fire and failure of equipment at VC Summer 1 ($5.6 million); and (4) $15.4 million attributable to Central Load Deviations (collectively, the "2021 Cook Rate Freeze Exceptions").

On May 12, 2022, counsel to class members sent a letter to the Authority regarding the 2021 Cook Rate Freeze Exceptions and requested additional information. The Authority provided the requested information on June 15, 2022. On June 22, 2022, the Authority received a letter from Central, which included comments, questions, objections, and requested additional information. The Authority responded to Central's letter and provided the same information provided to class counsel.

On September 9, 2022, class counsel filed a motion challenging the 2021 Cook Rate Freeze Exceptions claimed by the Authority in its 2021 Annual Compliance Report. The Authority submitted an initial response to the Court on September 19, 2022. On September 26, 2022, the Court entered an order denying, for now, Class Counsel's (i) motion to rule on the applicability of the 2021 Cook Rate Freeze Exceptions and (ii) request to appoint an independent auditor. Following the Court's order in 2022, the Authority, Central, and Class Counsel have discussed a path forward to resolve contested exceptions. As of the date hereof, the parties are still discussing a potential resolution of this matter.

2022 Annual Compliance Report. On April 28, 2023, the Authority filed its third Annual Cook Compliance Report (the "2022 Annual Cook Compliance Report") covering the period from January 1, 2022 through December 31, 2022 (the "2022 Reporting Period"). The 2022 Annual Cook Compliance Report identified eleven situations that fall within three categories of costs and expenses occurring during the 2022 Reporting Period that qualify as Cook Rate Freeze Exceptions, including (i) $85,262,331.10, resulting from various changes in law; (ii) $297,369,903.94 resulting from fires, and (iii) $20,607,225.51 resulting from named storms (collectively, the "2022 Cook Rate Freeze Exceptions").

2023 Annual Compliance Report. On April 30, 2024, the Authority filed its fourth Annual Cook Compliance Report (the "2023 Annual Cook Compliance Report") covering the period from January 1, 2023 through December 31, 2023 (the "2023 Reporting Period"). The 2023 Annual Cook Compliance Report identified nine situations falling within four categories of costs and expenses occurring during the 2023 Reporting Period that qualify as Cook Rate Freeze Exceptions, including (i) $63,643,742.18 resulting from various changes in law, (ii) $141,289,189.07 resulting from fires, (iii) $995,720.45 resulting from a named storm, and (iv) $260,612.20 resulting from an act of God and flood (collectively, the "2023 Cook Rate Freeze Exceptions").

The 2020 Cook Rate Freeze Exceptions, 2021 Cook Rate Freeze Exceptions, 2022 Cook Rate Freeze Exceptions, and 2023 Cook Rate Freeze Exceptions identified by the Authority in the respective Annual Cook Compliance Reports and including costs directly resulting from the costs of debt incurred as to the Cook Exceptions Regulatory Asset, total $716,934,018.64 (the "2020 - 2023 Cook Rate Freeze Exceptions Costs").

The Authority will continue to file the Annual Cook Compliance Reports required by the Cook Settlement Agreement. The Annual Cook Compliance Report covering the period from January 1, 2024 through December 31, 2024 (the "2024 Reporting Period") is required to be filed by the Authority by April 30, 2025 and will, among other things, update the Court regarding any previously identified Cook Rate Freeze Exceptions and identify new or ongoing costs and expenses occurring during the 2024 Reporting Period that qualify as Cook Rate Freeze Exceptions.

Settlement Discussions

The Authority, Central, and Class Counsel reached an agreement to resolve certain disputes arising from the Cook Rate Freeze Exceptions and the Authority's compliance with specific portions of the Cook Settlement Agreement (as more particularly described herein, the "Exceptions Agreement"). The terms of the Exceptions Agreement were approved by Class Counsel and the boards of the Authority and Central. The Exceptions Agreement also requires approval of the Court pursuant to the terms of the Cook Settlement Agreement and the Final Approval Order. (see Note 15- Subsequent Events for further discussion)

The Exceptions Agreement provides that the amount recoverable in rates by the Authority for certain Cook Rate Freeze Exceptions identified in previous Annual Cook Compliance Reports will be $550 million ("Resolution Amount"). The Authority can collect the Resolution Amount, interest incurred on debt issued to finance the Resolution Amount from January 1, 2025 to June 30, 2025, and the cost of issuance of debt issued to finance such interest and the Resolution Amount (collectively, the "Recovery Amount") over a 14.5-year period beginning July 1, 2025 and ending December 31, 2039.

The Authority will recover the Recovery Amount through the "Cook Charge," which shall consist of the debt service on the debt issued to finance the Recovery Amount plus amounts to reflect the Minimum Capital Improvement Requirement at 8%, payment to the State, and sums in lieu of taxes on such debt service. The Authority will begin collecting the Cook Charge from Central and non-Central customers in July 2025.

The Authority also will be able to collect debt service after the Rate Freeze Period on the Change of Law Effluent Limit Guidelines Exception (the "ELG Exception") consistent with the Authority's cost of service calculations used for retail ratemaking and Central's cost of service, as provided in the Central Agreement (as defined herein). The Exceptions Agreement affirms the right of the Authority to collect debt service on the ELG Exception after the Rate Freeze Period.

Aside from the Resolution Amount and debt service on the ELG Exception after the Rate Freeze Period, the Authority will not recover costs attributable to or expenses incurred for any Cook Rate Freeze Exceptions event or condition which occurred during the Rate Freeze Period and was previously identified in Annual Compliance Reports (the "Excluded Amounts"). In addition, the Excluded Amounts include Cook Rate Freeze Exceptions which occurred in 2024 and had not been previously identified in Annual Compliance Reports. The Authority also agreed to transfer $11.5 million of the

Resolution Amount into the Capital Improvement Fund (as defined herein), representing the capital portion of the Excluded Amounts, net of third-party contributions, to reimburse the fund for these capital expenditures.

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

The Authority filed a claim on October 2, 2015, against the U.S. Army Corps of Engineers ("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 and that the COE owes the Authority approximately $5.3 million in contract payments for 2015. 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 credit and a credit in the amount of $716,874 was due to the COE for 2015. 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 Board denied the Authority's appeals and remanded to the parties for "negotiation for the value of the additional capacity for the final 20 years of the contract performance period based on the contract." An agreement in principle was reached on July 26, 2024, and final terms are under discussion.

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, 2024, the Authority had 128 employees participating in the State ORP and consequently the related payments are not material.

Effective July 1, 2023 the employer rate for both the SCRS and ORP is 18.41 percent and the Employee rate is 9.0 percent. There is no scheduled rate increase or decrease as of December 31, 2024. 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. The actuarial assumed rate of return was set at 7.50 percent, net of investment expense, for fiscal years 2011 through 2017, 7.25 percent for fiscal years 2018 through 2021, then 7 percent beginning with fiscal year 2021. The rate was composed of 2.75 percent inflation and 4.75 percent real rate of return through fiscal year 2016; 2.25 percent inflation and 5.25 percent real return for fiscal year 2017; 2.25 percent inflation and 5.00 percent real return for fiscal years 2018 through 2021, and 2.25 percent inflation and 4.75 percent real return beginning with fiscal year 2021.

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 2024, 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, 2024, the Authority reported a liability of $279.6 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, 2024 and determined by an actuarial valuation as of July 1, 2023. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $27.5 million paid to SCRS for the year ended June 30, 2024 relative to the actual contributions of $2.5 billion from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2024 and 2023 are as follows:

	June 30, 2024	June 30, 2023
Authority's proportion of the net pension liability (%)	**1.14%**	1.19%
Authority's proportion of the net pension liability (millions)	**$267.5**	$290.2
Authority's covered payroll (millions)	**$147.3**	$143.9
Authority's proportion of the net pension liability as a percentage of its covered payroll	**182%**	202%
Plan fiduciary net position as a percentage of the total pension liability	**61.80%**	58.60%

For the year ended December 31, 2024, the Authority recognized a pension expense of $16.8 million, the Authority's proportionate share of the total pension expense. At December 31, 2024, 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	**$ 8,859**	**$ 337**
Changes of assumptions	**4,720**	**0**
Net difference between projected and actual earnings on pension plan investments	**0**	**10,326**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**0**	**15,433**
Authority's contributions subsequent to the measurement date	**13,855**	**0**
Total	**$ 27,434**	**$ 26,096**

The Authority reported $13.9 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, 2025. 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, 2024. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2024, was 3.616 years for SCRS.

Year Ending December 31:	
	(Thousands)
2025	**$ (12,070)**
2026	**4,955**
2027	**(2,690)**
2028	**(2,712)**
Total	**$ (12,517)**

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 was recognized as a reduction of the net pension liability in the year ended 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)

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, 2024:

- **Measurement Date**	**June 30, 2024**
- **Valuation Date**	**July 1, 2023**
- **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, 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%

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, 2024, 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%**	**6.23%**	**2.86%**
Private Equity	**9.00%**	**9.60%**	**0.86%**
Real Assets			
Real Estate	**9.00%**	**4.30%**	**0.39%**
Infrastructure	**3.00%**	**7.30%**	**0.22%**
Diversified Credit			
Bonds	**26.00%**	**2.60%**	**0.68%**
Private Debt	**7.00%**	**6.90%**	**0.48%**
Total Expected Real Return	**100.0%**		**5.49%**
Inflation for Actuarial Purposes			**2.25%**
Total Expected Nominal Return			**7.74%**

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 (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%	6.62%	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%

Sensitivity Analysis - For the measurement date as of June 30, 2024, 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 4.00% 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	**$ 359,513**	**$ 279,574**	**$ 206,012**

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

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, 2024, the Authority reported an asset of $4.5 million and a liability of $12.3 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	**$ 20**	**$ 0**
Changes of assumptions	**0**	**0**
Net difference between projected and actual earnings on pension plan investments	**780**	**110**
Authority's contributions subsequent to the measurement date	**123**	**0**
Total	**$ 923**	**$ 110**

The Authority reported $123,000 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, 2025. 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, 2024.

Year Ending December 31:		
	(Thousands)	
2025	**$**	**20**
2026		**146**
2027		**(227)**
2028		**0**
2029		**0**
Total	**$**	**(61)**

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

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, 2024, and 2023, the Authority had a pension liability of $0.8 million and $8.3 million, respectively. The Authority has a regulatory asset balance of approximately $8.5 million and $10.5 million for the unfunded portion of pension benefits at December 31, 2024 and 2023, 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, 2024.

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 1,181 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, 2024, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	**1,181**
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	**0**
Active Plan Members	**1,534**
Total Plan Members	**2,715**

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

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, 2024 and 2023 were as follows:

	2024	2023
	(Thousands)	
Total OPEB Liability	**$ 273,820**	$ 247,327
Plan fiduciary net position	**112,588**	97,290
Authority's net OPEB liability	**$ 161,232**	$ 150,037
Plan fiduciary net position as a percentage of the total OPEB liability	**41.12%**	39.34%

Actuarial Methods and Assumptions - The total OPEB liability was determined by an actuarial valuation as of June 30, 2022 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; 23 years remaining as of the beginning of FYE24
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, 2023 as conducted for the South Carolina Retirement Systems (SCRS)
Mortality	For healthy retirees, the gender-distinct PubH-2010 (Headcount Weighted) Healthy Retiree mortality tables for General Employees projected on a fully generational basis using the ultimate mortality improvement rates from Scale MP-2020.
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 6.25% declining to an ultimate rate of 4.25% after 14 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 Allocation at June 30, 2024:

Asset Class	Target Allocation	Long-Term Expected Real Rate of Return
Cash	**2.41%**	**0.04%**
Fixed Income	**97.59%**	**5.19%**
Total Blended Average	**100.0%**	**5.23%**

The rate of return for 2024 on the Trust was 1.8 %.

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 3.97% (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, 2024

Measurement period ending June 30	**2024**	2023
	(Thousands)	
Service Cost	**$ 5,228**	$ 6,052
Interest on the total OPEB liability	**9,773**	8,910
Difference between expected and actual experience	**2,663**	(40,154)
Changes of Assumptions	**20,081**	(16,422)
Benefit payments	**(11,252)**	(10,125)
Net change in total OPEB liability	**26,493**	(51,739)
Total OPEB liability - beginning	**247,327**	299,066
Total OPEB liability - ending (a)	**$ 273,820**	$ 247,327
Plan fiduciary net position		
Employer contributions	**$ 24,673**	$ 19,243
OPEB plan net investment income	**2,046**	(6,923)
Benefit payments	**(11,252)**	(10,125)
OPEB plan administrative expense	**(169)**	(154)
Net change in plan fiduciary net position	**15,298**	2,041
Plan fiduciary net position - beginning	**97,290**	95,249
Plan fiduciary net position - ending (b)	**$ 112,588**	$ 97,290
Net OPEB liability - ending (a) - (b)	**$ 161,232**	$ 150,037
Plan fiduciary net position as a percentage of total OPEB liability	**41.12%**	39.34%
Covered-employee payroll (dollars)	**$169,159,965**	$159,216,510
Net OPEB liability as a percentage of covered-employee payroll	**95.31 %**	94.23 %

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, 2024.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	**$ 206,439**	**$ 161,232**	**$ 124,620**

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

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, 2024.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	**$ 116,352**	**$ 161,232**	**$ 218,512**

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	$ 198,230

OPEB Expense and Deferred Outflows (Inflows) of Resources Related to OPEB - For the year ended December 31, 2024, the Authority recognized OPEB expense of $15.9 million. At December 31, 2024, 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	**$**	**5,648**	**$**	**29,317**
Changes of assumptions		**24,823**		**12,170**
Net difference between projected and actual earnings on OPEB plan investments		**18,279**		**0**
Authority's contributions subsequent to the measurement date		**8,932**		**0**
Total	**$**	**57,682**	**$**	**41,487**

The Authority reported $8.9 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, 2025. 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, 2024.

Year Ending December 31:		
(Thousands)		
2025	**$**	**8,690**
2026		**3,207**
2027		**(1,397)**
2028		**(4,907)**
2029		**387**
Thereafter		**1,282**
Total	**$**	**7,262**

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)

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, 2024 and 2023 were both approximately $13.5 million and $13.2 million, respectively.

The Authority recorded a regulatory asset of approximately $3.1 million at December 31, 2024. 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 2024 and 2023, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:		**2024**		2023
		(Millions)		
Central	**$**	**1,109**	$	1,050

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, 2024 and 2023 was $1.6 million and $2.4 million, respectively.

Note 14 – 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 15 – Subsequent Events

Nuclear Asset Request for Proposal

The Authority has engaged a consultant in January 2025 to conduct a Request for Proposals (RFP) process to evaluate uses for Summer Nuclear Units 2 and 3 and related assets. The Authority has announced it would be issuing an RFP (the "2025 Nuclear RFP") soliciting proposals from parties interested in acquiring one or both of Summer Nuclear Units 2 and 3 and the related assets, completing one or both units or pursuing alternative uses of the equipment and/or the site. Responses to the 2025 Nuclear RFP are currently expected to be due on May 5, 2025, after which the Authority may select one or more qualified respondents to participate in the next phase of the RFP process. The acceptance of any proposal submitted to the 2025 Nuclear RFP is subject to approval of the Board and may be subject to other regulatory oversight and approvals. The Authority is unable to predict the outcome of this RFP process, including whether any proposal will be accepted or any transaction ultimately consummated.

Exceptions Dispute

Dispute Regarding Cook Rate Freeze Exceptions and Proposed Resolution

The Authority, Central and Class Counsel engaged in negotiations to resolve the Exceptions Dispute along with the Cook-related Items and certain Central-Authority audit disputes (collectively, the "Disputes"). In January 2025, the parties reached an agreement to resolve the Disputes (the "Exceptions Agreement"). A timeline of events pertaining to these matters is as follows:

On June 9, 2021, as allowed by the Cook Settlement Agreement, Central asked the Court to appoint an independent auditor to review the Authority's compliance with respect to three transactions: (i) using funds specifically allocated for capital projects to retire a scheduled balloon payment in 2023 while borrowing new money to fund existing capital project needs, (ii) restructuring existing debt, and (iii) using funds on hand to pay the first $65 million installment to the Common Benefit Fund (the "Cook-related Items"). On September 10, 2021, the Court deferred any judicial action on Central's request.

On May 12, 2022, counsel to the class members (the "Class Counsel") sent a letter to the Authority regarding the 2021 Cook Rate Freeze Exceptions and requested additional information. The Authority provided the requested information on June 15, 2022. On June 22, 2022, the Authority received a letter from Central, which included comments, questions, objections, and requested additional information. The Authority responded to Central's letter and provided the same information provided to Class Counsel.

On September 9, 2022, Class Counsel filed with the Court a motion challenging the 2021 Cook Rate Freeze Exceptions identified by the Authority in its 2021 Annual Cook Compliance Report. The Authority submitted an initial response on September 19, 2022. On September 26, 2022, the Court entered an order denying Class Counsel's (i) motion to rule on the applicability of the 2021 Cook Rate Freeze Exceptions and (ii) request to appoint an independent auditor.

The objections of Central and Class Counsel to the Authority's implementation of the Cook Rate Freeze Exceptions described above are referred to herein as the "Exceptions Dispute."

Exceptions Agreement

As noted above, the parties negotiated an Exceptions Agreement in January 2025. The terms of the Exceptions Agreement include, among other things, the following:

- Resolution Amount – The Authority will recover $550 million for certain Cook Rate Freeze Exceptions costs and expenses attributable to or incurred during the Rate Freeze Period relating to the following Cook Rate Freeze Exceptions identified in previous Annual Cook Compliance Reports (i) mine safety and health administration order and fire resulting in the closure of Foresight's Sugar Camp Mine, (ii) Executive Orders and actions related to the Russian invasion of Ukraine and public enemy actions by Russia and Vladimir Putin and (iii) interest accumulated during the Rate Freeze Period used to finance the Cook Rate Freeze Exceptions.

- Recovery Amount – The Authority will recover the Resolution Amount, plus interim interest incurred on debt to finance the Resolution Amount from January 1, 2025 through June 30, 2025, plus the cost of issuance of debt issued to finance the Resolution Amount and the interim interest, the sum of which equals the Recovery Amount. The Recovery Amount will be financed and collected via the Cook Exceptions Charge (referred to as the Exceptions Charge) over the 14.5 year period from July 1, 2025 to December 31, 2039. The estimated impact on customers' bills is an increase of approximately 3%, an average increase of less than $5 on the monthly bill of a typical residential customer.

- Cook Charge – The Cook Charge will consist of the debt service on the debt issued to finance the Recovery Amount and amounts to collect a contribution to the Capital Improvement Fund of 8%, payments to the State and sums in lieu of taxes on that debt service. The Cook Charge will be calculated separately from the Authority's cost of service calculations used for the Authority's retail ratemaking and Central's cost of service pursuant to the Central Agreement. The Cook Charge will be allocated 65.4% to Central and 34.6% to the Authority's non-Central customers. The Authority will begin collecting the Cook Charge from its retail customers through its deferred cost recovery rider and from Central on its invoices beginning in July 2025.

- In addition, the Authority will retain the right to collect debt service after the Rate Freeze Period on the ELG Exception consistent with the Authority's cost of service calculations used for retail ratemaking and Central's cost of service, as provided in the Central Agreement.

- Other than the Resolution Amount and debt service on the ELG Exception, the Authority will not recover the Excluded Amounts. The Excluded Amounts include new Cook Rate Freeze Exceptions which occurred in 2024 and had not been previously identified in Annual Cook Compliance Reports.

- The Authority will transfer $11.5 million of the Resolution Amount into the Capital Improvement Fund, representing the capital portion of the Excluded Amounts, net of third-party contributions, to reimburse the fund for these capital expenditures.

On February 6, 2025, the board of trustees of Central approved the Exceptions Agreement. The Board approved the Exceptions Agreement on February 12, 2025. Santee Cooper, Central, and Class Counsel executed the Exceptions Agreement on February 25, 2025. The Exceptions Agreement provides that within 30 days of the agreement having been approved by both the Board and Central's board of trustees, the Authority, Central and Class Counsel will submit a consent motion to the Court requesting approval of the Exceptions Agreement.

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Required Supplemental Financial Data (Unaudited):

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

Years Ended in June 30,	**2024**	2023	2022	2021	2020	2019	2018	2017	2016	2015
Authority's proportion of the net pension liability (%)	**1.14%**	1.19%	1.21%	1.28%	1.28%	1.35%	1.43%	1.43%	1.45%	1.44%
Authority's proportion of the net pension liability (millions)	**$267.5**	$290.2	$295.2	$278.9	$327.9	$309.7	$321.8	$323.1	$309.7	$273.6
Authority's covered payroll (millions)	**$147.3**	$143.9	$148.9	$152.7	$149.7	$151.1	$156.5	$153.7	$147.7	$140.7
Authority's proportion of the net pension liability as a percentage of its covered payroll	**182%**	202%	198%	183%	219%	205%	206%	210%	210%	194%
Plan fiduciary net position as a percentage of the total pension liability	**61.8%**	58.6%	57.1%	60.7%	50.7%	54.4%	54.1%	53.3%	56.9%	59.9%

Schedule of Pension Plan Contributions
Required Supplementary Information
(Millions)

Years Ended December 31,	2024	2023	2022	2021	2020	2019	2018	2017	2016	2015
Required Contributions:										
From the Authority	**$ 28.10**	$ 25.60	$23.20	$22.10	$22.10	$20.60	$19.80	$17.70	$15.60	$14.80
From employees	**13.80**	12.80	12.30	12.50	12.90	12.40	12.80	12.60	11.80	11.00
Contributions in relation to the required contributions:										
From the Authority	**$ 28.10**	$ 25.60	$23.20	$22.10	$22.10	$20.60	$19.80	$17.70	$15.60	$14.80
From employees	**13.80**	12.80	12.30	12.50	12.90	12.40	12.80	12.60	11.80	11.00
Contribution deficiency (excess)	**0**	0	0	0	0	0	0	0	0	0
Authority's covered payroll	**152.80**	142.80	137.20	138.30	143.60	138.20	142.30	142.70	140.10	136.40
Authority's contributions as a percentage of covered payroll	**18.00%**	18.00%	17.00%	16.00%	15.40%	14.90%	13.90%	12.40%	11.10%	10.90%

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

Measurement period ending June 30,	2024	2023	2022	2021	2020	2019	2018[1]
Service Cost	**$ 5,228**	$ 6,052	$ 7,098	$ 6,899	$ 6,821	$ 4,641	$ 5,405
Interest on the total OPEB liability	**$ 9,773**	8,910	8,755	9,573	9,425	10,375	10,073
Difference between expected and actual experience	**$ 2,663**	(40,154)	177	7,692	242	(12,859)	(291)
Changes of Assumptions	**20,081**	(16,422)	(260)	3,975	(2,717)	44,641	0
Benefit payments	**$ (11,252)**	(10,125)	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
Net change in total OPEB liability	**$ 26,493**	(51,739)	5,757	18,326	4,420	37,861	7,934
Total OPEB liability - beginning	**$ 247,327**	299,066	293,309	274,983	270,563	232,702	224,768
Total OPEB liability - ending (a)	**$ 273,820**	$ 247,327	$ 299,066	$ 293,309	$ 274,983	$ 270,563	$ 232,702
Plan fiduciary net position							
Employer contributions	**$ 24,673**	$ 19,243	$ 20,283	$ 18,573	$ 18,812	$ 27,483	$ 14,455
OPEB plan net investment income	**2,046**	(6,923)	(20,631)	(1,686)	5,717	5,501	(120)
Benefit payments	**(11,252)**	(10,125)	(10,013)	(9,813)	(9,351)	(8,937)	(7,253)
OPEB plan administrative expense	**(169)**	(154)	(171)	(167)	(153)	(126)	(104)
Net change in plan fiduciary net position	**15,298**	2,041	(10,532)	6,907	15,025	23,921	6,978
Plan fiduciary net position - beginning	**97,290**	95,249	105,781	98,874	83,849	59,928	52,950
Plan fiduciary net position - ending (b)	**$ 112,588**	$ 97,290	$ 95,249	$ 105,781	$ 98,874	$ 83,849	$ 59,928
Net OPEB liability - ending (a) - (b)	**$ 161,232**	$ 150,037	$ 203,817	$ 187,528	$ 176,109	$ 186,715	$ 172,774
Plan fiduciary net position as a percentage of total OPEB liability	**41.12%**	39.34%	31.85%	36.06%	35.96%	30.99%	25.75%
Covered-employee payroll	**$169,159,965**	$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	**95.31%**	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
2024	**$ 14,642**	**$ 20,953**	**$ (6,311)**	**$ 177,092**	**11.83%**
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
2024	**4.00%**
2023	4.00%
2022	3.00%
2021	3.50%
2020	3.50%
2019	4.50%

Schedule of Investment Returns
Required Supplementary Information

	2024	2023	2022	2021	2020	2019	2018[1]
Annual money-weighted rate of return, net of investment expenses	**1.80%**	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.

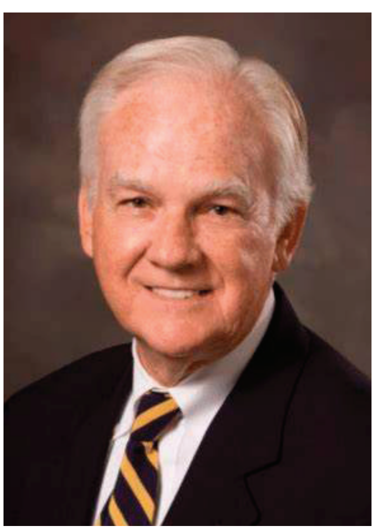
Director Singleton is President of Singleton Properties, a real estate investment and sales firm.

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.

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.

Alyssa Leigh Richardson
6th Congressional District
North Charleston, South Carolina

Director Richardson is the Founder and CEO of Develop South Carolina, a real estate development and consulting firm focused on attainable housing, and Of Counsel for Wyche, a full-service law firm.

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.

A. Berl Davis Jr.
Ex Officio, Central Electric Power Cooperative Inc.
Ridgeland, South Carolina

Director Davis is the Chairman of the Central Electric Power Cooperative Inc. Board of Trustees and the President and CEO of Palmetto Electric Cooperative.

Notes:

On Aug. 1, 2024, A. Berl Davis Jr. joined the Board of Directors as an Ex Officio Member, replacing E. Paul Basha, and represents Central Electric Power Cooperative Inc.

On Jan. 20, 2025, Chad T. Lowder joined the Board of Directors as an Ex Officio Member, replacing Robert G. Ardis III, and represents Central Electric Power Cooperative Inc.

David F. Singleton assumed the role of First Vice Chairman, effective Jan. 27, 2025.

John S. West assumed the role of Second Vice Chairman, effective Jan. 27, 2025.

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

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 Organizational Culture 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:

Pamela J. Williams stepped down as Chief Public Affairs Officer and General Counsel on Jan. 3, 2025, with plans to retire on March 31, 2025. Carmen H. Thomas was appointed as Chief Legal Officer and General Counsel, effective Jan. 4, 2025.

B. Shawan Gillians was appointed as Chief Strategy and Communications Officer, effective Jan. 4, 2025.

Office Locations

MONCKS CORNER OFFICE
Santee Cooper Headquarters
1 Riverwood Drive
Moncks Corner, SC 29461
843-761-8000
843-761-4122 (fax)

MYRTLE BEACH OFFICE
1703 Oak St.
Myrtle Beach, SC 29577
843-448-2411
843-626-1923 (fax)

APPENDIX B

SUMMARY OF CERTAIN PROVISIONS OF THE REVENUE OBLIGATION RESOLUTION

The following statements are summaries of certain provisions of the Revenue Obligation Resolution. Except as otherwise provided in this Official Statement, terms used under this caption which are defined in the Revenue Obligation Resolution, including, but not limited to those defined hereinafter, are used herein as so defined. Certain other provisions of the Revenue Obligation Resolution are summarized under the caption "SECURITY FOR THE 2026 BONDS."

Definitions of Certain Terms Used in Revenue Obligation Resolution

The following words and phrases are defined in the Revenue Obligation Resolution as hereinafter set forth.

"Capital Costs" shall mean the Authority's costs of (i) physical construction of or acquisition of real or personal property or interests therein for any project, together with incidental costs (including legal, administrative, engineering, consulting and technical services, insurance and financing costs), working capital and reserves deemed necessary or desirable by the Authority (including but not limited to costs of supplies, fuel, fuel assemblies and components or interests therein), and other costs properly attributable thereto; (ii) all capital improvements or additions, including but not limited to, renewals or replacements of or repairs, additions, improvements, modifications or betterments to or for any project; (iii) the acquisition of any other property (tangible or intangible), capital improvements or additions, or interests therein, deemed necessary or desirable by the Authority for the conduct of its business; (iv) any other purpose for which bonds, notes or other obligations of the Authority may be issued under the Enabling Act or under other applicable State statutory provisions (whether or not also classifiable as an operating expense); and (v) the payment of principal, interest, and redemption, tender or purchase price of (a) any Obligations, Commercial Paper or other indebtedness issued by the Authority for the payment of any of the costs specified above, including capitalized interest on such indebtedness, or (b) any indebtedness issued by the Authority to refund any indebtedness described in the preceding clause (a).

"Event of Default" shall mean one or more of the events set forth herein under "Events of Default and Remedies Under the Revenue Obligation Resolution."

"Government Obligations" shall mean direct obligations of, or obligations the principal of and interest on which are unconditionally guaranteed by, the United States of America.

"Investment Securities" shall mean any of the following which at the time are legal investments under the laws of the State of South Carolina for the moneys held hereunder then proposed to be invested therein: (1) Government Obligations; (2) certificates which evidence ownership of the rights to payment of the principal of or interest on Government Obligations; (3) bonds, debentures, notes or participation certificates issued by the Bank for Cooperatives, the Federal Intermediate Credit Bank, the Federal Home Loan Bank System, the Export-Import Bank of the United States, Federal Land Bank, the Federal National Mortgage Association, the Tennessee Valley Authority, or any other agency or corporation which is or may hereafter be created by or pursuant to an Act of Congress of the United States as an agency or instrumentality thereof; (4) obligations of state and local government municipal bond issuers, provision for the payment of the principal of and interest on which shall have been made by deposit with a trustee or escrow agent of non-callable obligations described in (1), (2), or (3) of this subparagraph, the maturing principal of and interest on which when due and payable, shall provide sufficient funds to pay the principal of and interest on such obligations of state and local government municipal bond issuers (5) Public Housing Bonds, or Project Notes, fully secured by contracts with the United States; (6) repurchase agreements with banks that are members of the federal reserve system or with government bond dealers recognized as primary dealers by the Federal Reserve Bank of New York that are secured by securities described in (1) and (3) above having a current market value at least equal to one hundred two per cent (102%) of the amount of the repurchase agreement; (7) obligations of the State of South Carolina, (8) obligations of other states and investment contracts which obligations or investment contracts are rated at the time of purchase by each rating agency then maintaining a rating on the Obligations at the request of the Authority (each, a "Rating Agency") in one of the three highest rating categories (as determined without regard to any refinement or graduation of such rating by a numerical modifier or otherwise, a "Rating Category") of such Rating Agency; (9) deposits in interest bearing deposits or certificates of deposit or similar arrangements issued by any bank or national banking association (including the Trustee), which deposits, to the extent not insured by the Federal Deposit Insurance Corporation, shall be secured by Government Obligations or obligations described in clauses (2), (3), (4) or (7) of this paragraph, having a current market value (exclusive of accrued interest) at least equal to one hundred five percent (105%) of the amount of such deposits, which Government Obligations or obligations described in clauses (2), (3), (4) or (7) of this paragraph shall have been deposited in trust by such bank or national association with the trust department of the Trustee or with a federal reserve bank or branch or, with the written approval of the Authority and the Trustee, with another bank, trust company or national banking association for the benefit of the Authority and the appropriate fund or account as collateral security for such deposits; (10) corporate securities, including commercial paper and fixed income obligations, which are, at the time of purchase, rated by a Rating Agency in one of its three highest Rating Categories for comparable types of obligations; and (11) such other investments from time to time allowed under applicable law.

"Obligations" shall mean any obligations, issued in any form of debt, authorized by a supplemental resolution, including but not limited to bonds, notes, bond anticipation notes, and Qualified Swaps, which are delivered under the Revenue Obligation Resolution.

"Operation and Maintenance Expenses" shall mean the Authority's expenses of operating the System, including, but not limited to, all costs of purchased power, operation, maintenance, generation, production, transmission, distribution, repairs, replacements, engineering, transportation, administration and general, audit, legal, financial, pension, retirement, health, hospitalization, insurance, taxes and any other expenses actually paid or accrued, of the Authority applicable to the System, as recorded on its books pursuant to generally accepted accounting principles, subject to the limitations with respect to take or pay contracts as set forth under "Take or Pay Contracts." Operation and Maintenance Expenses shall not include (1) any costs or expenses for new construction, (2) charges for depreciation, (3) voluntary payments in lieu of taxes or (4) any taxes or tax payments now or hereafter required to be made to the State or any political subdivisions only out of surplus revenues, for example, payments required by Code Sections 58-31-90, 58-31-100 (2) and (3), and 58-31-110, Code of Laws of South Carolina 1976.

"Outstanding" shall mean, as of any date, Obligations issued pursuant to the Revenue Obligation Resolution, except: (1) any Obligations cancelled or paid at or prior to such date; (2) Obligations in lieu of or in substitution for which other Obligations have been delivered pursuant to the Revenue Obligation Resolution; and (3) Obligations the payment of the principal of and interest on which has been made or provided for in compliance with the defeasance provisions of the Revenue Obligation Resolution so as to cancel the lien of the Revenue Obligation Resolution.

"Permitted Investments" shall mean the obligations referred to in (1), (2), (3) and (4) of the definition of the term "Investment Securities".

"Qualified Swap" shall mean, to the extent from time to time permitted by law, with respect to Obligations, any financial arrangement (i) which is entered into by the Authority with an entity that is a Qualified Swap Provider at the time the arrangement is entered into, (ii) which is a cap, floor or collar; forward rate; future rate; swap (such swap may be based on an amount equal either to the principal amount of such Obligations of the Authority as may be designated or a notional principal amount relating to all or a portion of the principal amount of such Obligations); asset, index, price or market-linked transaction or agreement; other exchange or rate protection transaction agreement; other similar transaction (however designated); or any combination thereof; or any option with respect thereto, executed by the Authority for the purpose of moderating interest rate fluctuations or otherwise, and (iii) which has been designated in writing to the Trustee by the Authority as a Qualified Swap with respect to such Obligations.

"Qualified Swap Provider" shall mean an entity whose senior long term obligations, other senior unsecured long term obligations or claims paying ability, or whose payment obligations under an interest rate exchange agreement are guaranteed by an entity whose senior long term debt obligations, other senior unsecured long term obligations or claims paying ability, are rated either (i) at least as high as the third highest Rating Category of each Rating Agency, but in no event lower than any Rating Category designated by each such Rating Agency for the Obligations subject to such Qualified Swap, or (ii) any such lower rating categories which each such Rating Agency indicates in writing to the Authority and the Trustee will not, by itself, result in a reduction or withdrawal of its rating on the Outstanding Obligations subject to such Qualified Swap that is in effect prior to entering into such Qualified Swap.

"Revenues" shall mean all the revenues, income, profits, tolls, rents, charges and returns of the Authority derived from its ownership or operation of the System, including the proceeds of any insurance covering business interruption loss relating to the System, but excluding other insurance proceeds and customer deposits.

System

The Authority's System, as defined in the Revenue Obligation Resolution (herein, the "System"), consists generally of (a) facilities for the purpose of acquiring, controlling, storing, preserving, treating, distributing and selling water for navigation, power, irrigation or reclamation, and (b) plants, works, structures, facilities and equipment for the generation, manufacture, transmission or distribution of water power and electric power and energy, and of any other forms of power and energy when authorized by the Enabling Act. The System shall not include separate projects established by the Authority for any corporate purpose of the Authority other than those projects and purposes described hereinabove, nor separate systems described under "Separate Systems."

Revenue Fund

The Revenue Obligation Resolution continues, for so long as any of the Obligations are Outstanding, the Revenue Fund. The Revenue Fund shall be held in trust and administered by the Authority. The Authority covenants and agrees in the Revenue Obligation Resolution to pay into the Revenue Fund, as promptly as practical after the receipt thereof, all Revenues.

Funds and Accounts

For the purpose of providing for the payment of the principal of, premium, if any, and interest on the Obligations, the Revenue Obligation Resolution creates a Revenue Obligation Fund. Payments into the Revenue Obligation Fund shall be made prior to the payments required to be made from, or retained in, the Revenue Fund to cover the cost of operation and maintenance of the System and the payments required to be made into the Capital Improvement Fund.

Order of Payments From Revenue Fund

Under the Revenue Obligation Resolution, moneys shall be disbursed by the Authority from the Revenue Fund in the following order:

1. *Revenue Obligation Fund*: To pay when due to the Trustee the Revenue Obligation Fund Payments.

2. *Operating and Maintenance*: To pay expense of operation and maintenance.

3. *Subordinated Debt*: To pay, when due, amounts due and owing with respect to the payment of principal and interest on amounts issued under the Note Resolution (See "Junior Lien Obligations" below), including Commercial Paper Notes and the Authority's payment obligations under the CP Reimbursement Agreements and the Revolving Credit Agreements (as such terms are defined in the Official Statement).

4. *Capital Improvement Fund*: To pay during each Fiscal Year into the Capital Improvement Fund amounts at least equal to the Minimum Capital Improvement Requirement.

Any moneys remaining in the Revenue Fund each month after making the payments referenced above may be used by the Authority for any corporate purpose of the Authority.

Certain Moneys Not Required to be Deposited in Revenue Fund

The Revenue Obligation Resolution does not require the deposit into the Revenue Fund of any of the revenues, income, receipts, profits or other moneys of the Authority derived by the Authority through the ownership or operation of any separate system described under the section "Separate Systems" or through the ownership or operation of any separate project referred to under the section "System".

Authorization of Obligations

At any time one or more series of Obligations may be issued pursuant to the Revenue Obligation Resolution, upon the terms set forth in a Series Resolution, for any corporate purpose of the Authority, including the refunding or purchase of Obligations, provided there is no default under the Revenue Obligation Resolution.

Separate Systems

The System shall not include (i) any facilities for the purpose of providing water for sale to residential, commercial, agricultural or industrial customers or other governmental entities, or (ii) any facilities for the generation of any form of power and energy, or for the transmission and distribution of any form of power and energy, and any incidental properties constructed, acquired or leased in connection therewith, constructed or acquired by the Authority as a separate system, and if constructed or acquired with the proceeds of sale of bonds or other evidences of indebtedness, which bonds or other evidences of indebtedness are payable solely from the revenues or other income derived from the ownership or operation of such separate utility system, and may be further secured by a pledge of Revenues junior and subordinate to the pledge securing the Obligations and payable therefrom, but only after the revenues and other income derived from the ownership or operation of such separate utility system and pledged to the payment of such bonds or other indebtedness are so applied in accordance with the proceedings providing for the issuance of such bonds or other indebtedness.

Junior Lien Obligations

The Authority adopted a resolution on March 20, 2017, and as further amended, modified, restated or supplemented from time to time in accordance with its terms and the terms hereof, (the "Note Resolution") for the issuance of bonds, notes, bond anticipation notes, warrants, certificates or other obligations or evidences of indebtedness the payment of which shall be made from Revenues and such payment shall be junior and subordinate to the payment of the Obligations.

Insurance

The Revenue Obligation Resolution requires the Authority to insure such of its various properties as are usually insured by utilities owning like properties in similar amounts and coverages, with insurance companies, and to carry liability insurance in reasonable amounts.

Sale, Lease or Other Disposition of Properties

Subject to the next sentence, the Authority may sell, lease, or otherwise dispose of any part of its properties on such terms and conditions as may be prescribed by its Board of Directors. The Authority shall not take any action described in the preceding sentence unless, in the judgment of the Authority's Board of Directors, such action is desirable in the conduct of the Authority's business and does not materially impair the Authority's ability to comply with the rate covenant provisions of the Revenue Obligation Resolution.

Take or Pay Contracts

The Revenue Obligation Resolution does not prohibit the Authority from entering into take or pay contracts, including take or pay contracts with a separate system described under section "Separate Systems," to purchase power under conditions whereby payments the Authority is required to make may be calculated, in whole or in part, on the basis of power which the Authority does not purchase, require or obtain for whatever reasons. However, payments made by the Authority under such a take or pay contract for power not available for any reason other than an emergency or forced outage lasting not more than one year or normal and regularly scheduled maintenance outage may not be treated as Operation and Maintenance Expenses.

Capital Improvement Fund

The Revenue Obligation Resolution requires the deposit annually into the Capital Improvement Fund of an amount at least equal to the Minimum Capital Improvement Requirement defined as follows: an amount, which, together with the amounts deposited in the Capital Improvement Fund in the two immediately preceding Fiscal Years, will be at least equal to 8% of the revenues required by the Revenue Obligation Resolution to be paid into the Revenue Fund in the three immediately preceding Fiscal Years. Certain payments not made into the Capital Improvement Fund may be considered as a payment towards fulfillment of the Minimum Capital Improvement Requirement.

The moneys on deposit in the Capital Improvement Fund shall be used solely to pay Capital Costs.

Events of Default and Remedies Under the Revenue Obligation Resolution

A happening of one or more of the following constitutes an Event of Default under the Revenue Obligation Resolution:

(a) default in the due and punctual payment of any interest on any Obligation which shall continue for a period of 30 days; or

(b) default in the due and punctual payment of the principal of any Obligation, whether at the stated maturity thereof, at the mandatory redemption date, at the redemption date or upon declaration of acceleration; or

(c) the Authority shall violate or fail to perform any of its covenants or agreements contained in the Revenue Obligation Resolution for 90 days after written notice of default is given to it by the Trustee or by the holder of any Obligation; or

(d) a default shall have occurred in respect of any bond, debenture, note or other evidence of indebtedness of the Authority, or in respect of any obligations of the Authority under any financing lease, whether now outstanding or existing or issued or otherwise undertaken hereafter, or under any indenture, resolution, lease or other agreement or instrument under which any such bond, debenture, note or other evidence of indebtedness or any such lease obligation has been or may be issued or by which any of the foregoing is or may be governed or evidenced, which default shall have resulted in the principal amount of such bond, debenture, note or other evidence of indebtedness or lease obligation becoming due and payable prior to its stated maturity or which default shall have been a default in the payment of principal when due and payable; or

(e) a decree or order by a court having jurisdiction in the premises shall have been entered judging the Authority as bankrupt or insolvent, or approving as properly filed a petition seeking reorganization or arrangement of the Authority under the Federal bankruptcy laws or any similar applicable Federal or South Carolina law, and such decree or order shall have continued undischarged or unstayed for a period of forty (40) days; or a decree or order of a court having jurisdiction in the premises for the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of the Authority or any of its property, or for the winding-up or liquidation of the Authority or any of its property, shall have been undischarged and unstayed for a period of sixty (60) days; or

(f) the Authority shall institute proceedings to be adjudicated a voluntary bankrupt, or shall consent to the filing of a bankruptcy proceeding against it, or shall file a petition or answer or consent seeking reorganization or arrangement under the Federal bankruptcy laws or any similar applicable Federal or South Carolina law, or shall consent to the filing of any such petition, or shall consent to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of the Authority or of any of its property, or shall make an assignment for the benefit of creditors, or shall admit in writing its insolvency or inability to pay its debts generally as they become due, or any action shall be taken by the Authority in furtherance of any of the foregoing aforesaid purposes.

Remedies

If an Event of Default has occurred, and shall not have been remedied, the Trustee or the holders of not less than 25% in principal amount of the Obligations then outstanding may declare the principal of all Obligations and the interest accrued thereon to be immediately due and payable, but such declaration may be rescinded under certain circumstances. The right of the Trustee or of the holders of not less than 25% in principal amount of the Obligations to make any such declaration as aforesaid, however, is subject to the condition that if, at any time after such declaration, but (i) before any judgment or decree for the payment of moneys due shall have been obtained or entered and has been discharged, (ii) before possession and control of the business and properties of the System have been taken pursuant to the Revenue Obligation Resolution, and (iii) before the Obligations shall have matured by their terms, all overdue installments of interest upon the Obligations, together with the reasonable and proper charges, expenses and liabilities of the Trustee and the holders of Obligations and their respective agents and attorneys and all other sums then payable by the Authority under the Revenue Obligation Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall either be paid by or for the account of the Authority or provisions satisfactory to the Trustee shall be made for such payment, and all defaults under the Obligations or under the Revenue Obligation Resolution (other than the payment of principal and interest due and payable solely by reason of such declaration) shall be made good or be secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate shall be made therefor, then and in every such case the holders of 25% in principal amount of the Obligations then Outstanding, by written notice to the Authority and to the Trustee, may rescind such declaration and annul such default in its entirety, or if the Trustee shall have acted without a direction from the holders of not less than a majority in principal amount of the Obligations Outstanding at the time of such request, and if there shall not have been theretofore delivered to the Trustee written direction to the contrary by the holders of not less than a majority in principal amount of the Obligations then Outstanding, then any such declaration shall ipso facto be deemed to be rescinded and any such default and its consequences shall ipso facto be deemed to be annulled, but no such rescission and annulment shall extend to or affect any subsequent default or impair or exhaust any right or power consequent thereon.

The Authority covenants that if an Event of Default shall happen and shall not have been remedied, the Authority will account, as a trustee of an express trust, for all Revenues and other moneys, securities and funds pledged under the Revenue Obligation Resolution.

Inspection of Authority's Books and Records

The Authority covenants that if an Event of Default shall have happened and shall not have been remedied, the books of record and accounts of the Authority shall at all times be subject to the inspection and use of the Trustee and any persons holding at least twenty-five per cent 25% of the principal amount of Obligations Outstanding and of their respective agents and attorneys.

Payment of Funds to Trustee; Application of Revenues

The Authority covenants that if an Event of Default shall happen and shall not have been remedied, the Authority, upon demand of the Trustee, shall pay over to the Trustee, all moneys, securities and funds then held by the Authority.During the continuance of an Event of Default, the Revenues received by the Trustee, or Owners' Committee, as the case may be, whether pursuant to the provisions of the preceding paragraph or any other provision of the Revenue Obligation Resolution, or as the result of taking possession of the business and properties of the System, shall be applied by the Trustee or Owners' Committee, as the case may be, first to the payment of the reasonable and proper charges, expenses and liabilities paid or incurred by the Trustee or Owners' Committee, as the case may be (including the cost of securing the services of any engineer or firm of engineers selected for the purpose of rendering advice with respect to the operation, maintenance, repair and replacement of the System necessary to prevent any loss of Revenues, and with respect to the sufficiency of the rates and charges for power and energy sold, furnished or supplied by the System), and thereafter to the payment of the reasonable and necessary cost of operation, maintenance, repair and replacement of the System.

In the event that at any time the funds held by the Trustee and the Paying Agents for the Obligations shall be insufficient for the payment of the principal of and premium, if any, and interest then due on the Obligations, such funds (other than funds held for the payment or redemption of particular Obligations which have theretofore become due at maturity or by call for redemption) and all Revenues and other moneys received or collected for the benefit or for the account of holders of the Obligations by the Trustee shall be applied as follows:

Unless the principal of all of the Obligations shall have become or have been declared due and payable,

First, to the payment to the persons entitled thereto of all installments of interest then due in the order of the maturity of such installments, earliest maturities first, and, if the amount available shall not be sufficient to pay in full any installment or installments of interest maturing on the same date, then to the payment thereof ratably, according to the amounts due thereon, to the persons entitled thereto, without any discrimination or preference; and

Second, to the payment to the persons entitled thereto of the unpaid principal and premium, if any, of any Obligations which shall have become due, whether at maturity or by call for redemption, in the order of their due dates, earliest maturities first, and if the amount available shall not be sufficient to pay in full all the Obligations due on any date, then to the payment thereof ratably, according to the amounts of principal and premium, if any, due on such date, to the persons entitled thereto, without any discrimination or preference.

If the principal of all of the Obligations shall have become or have been declared due and payable, to the payment of the principal and interest then due and unpaid upon the Obligations without preference or priority of principal over interest or of interest over principal, or of any installment of interest over any other installment of interest, or of any Obligation over any other Obligations, ratably, according to the amounts due respectively for principal and interest, to the persons entitled thereto without any discrimination or preference.

If and whenever all overdue installments of interest on all Obligations, together with the reasonable and proper charges, expenses and liabilities of the Trustee and the holders of Obligations, their respective agents and attorneys, and all other sums payable by the Authority under the Revenue Obligation Resolution including the principal and premium, if any, of and accrued unpaid interest on all Obligations which shall then be payable by declaration or otherwise, shall either be paid by or for the account of the Authority, or provision satisfactory to the Trustee shall be made for such payment, and all defaults under the Revenue Obligation Resolution or the Obligations shall be made good or secured to the satisfaction of the Trustee or provision deemed by the Trustee to be adequate shall be made therefor, the Trustee shall pay over to the Authority all moneys, securities, funds and Revenues then remaining unexpended in the hands of the Trustee (except moneys, securities, funds or Revenues deposited or pledged, or required by the terms of the Revenue Obligation Resolution to be deposited or pledged, with the Trustee), and thereupon the Authority and the Trustee shall be restored, respectively, to their former positions and rights under the Revenue Obligation Resolution. No such payment over to the Authority by the Trustee shall extend to or affect any subsequent default under the Revenue Obligation Resolution or impair any right consequent thereon.

Suits at Law or in Equity; Direction of Actions by Owners; Possession of System; Receivership

If an Event of Default shall happen and shall not have been remedied, then and in every such case, the Trustee, either in its own name or as trustee of an express trust, or as attorney-in-fact for the holders of the Obligations, or in any one or more of such capacities, by its agents and attorneys, shall be entitled and empowered to proceed forthwith and upon the written request of the holders of not less than 25% of the Obligations then Outstanding shall proceed forthwith to institute such suits, actions and proceedings at law or in equity for the collection of all sums due in connection with the Obligations and to protect and enforce its rights and the rights of the holders of the Obligations under the Revenue Obligation Resolution for the specific performance of any covenant herein contained, or in aid of the execution of any power herein granted, or for an accounting against the Authority as trustee of an express trust, or in the enforcement of any other legal or equitable right as the Trustee, being advised by counsel, shall deem most effectual to enforce any of its rights, or to perform any of its duties under the Revenue Obligation Resolution. The Trustee shall be entitled and empowered either in its own name or as a trustee of an express trust, or as an attorney-in-fact for the holders of the Obligations, or in one or more of such capacities, to file such proof of debt, amendment of proof of debt, claim, petition or other document as may be necessary or advisable in order to have the claims of the Trustee and of the holders of the Obligations allowed in any equity, receivership, insolvency, bankruptcy, liquidation, readjustment, reorganization or other similar proceedings relative to the Authority. For this purpose the Trustee is hereby irrevocably appointed the true and lawful attorney-in-fact of the respective holders of the Obligations (and the successive holders of the Obligations by taking and holding the same shall be conclusively deemed to have so appointed the Trustee) with authority to make and file in the respective names of the holders of the Obligations any such proof of debt, amendment of proof of debt, claim, petition or other document in any such proceedings, and to receive payment of any sums becoming distributable on account thereof, and to execute any such other papers and documents and to do and perform any and all acts and things for and on behalf of the holders of the Obligations as may be necessary or advisable in the opinion of the Trustee in order to have the respective claims of the Trustee and of the holders of the Obligations allowed in any such proceeding and to receive payment of and on account of such claims; provided, however, that nothing contained in the Revenue Obligation Resolution shall be deemed to give the Trustee any right to accept or consent to any plan or reorganization or compromise or otherwise take any action of any character in any such proceeding to waive or change in any way any right of any holder of Obligations.All rights of action under the Revenue Obligation Resolution may be enforced by the Trustee without the possession of any of the Obligations or the production thereof on the trial or other proceedings.

The holders of not less than a majority in principal amount of the Obligations at the time Outstanding, may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any trust or power conferred upon the Trustee.

At any time after the occurrence of an Event of Default and prior to the curing of such Event of Default, whether or not the principal of and premium, if any, and interest accrued on all the Revenue Obligations Outstanding shall have been declared immediately due and payable as a result of such Event of Default, the Trustee, as a matter of right against the Authority, without notice of demand, and without regard to the adequacy of the security for the Obligations shall, to the extent permitted by law, be entitled to take possession and control of the business and properties of the System. Upon taking such possession, the Trustee shall operate and maintain the System, make any necessary repairs, renewals and replacements in respect thereof, prescribe rates and charges for power and energy sold, furnished or supplied through the facilities of the System, collect the gross revenues resulting from the operation of the System, and perform all of the agreements and covenants contained in all contracts which the Authority is at the time obligated to perform. At any time the Trustee, shall be entitled to the appointment of a receiver of the business and property of the System, of the moneys, securities and funds of the Authority pledged under the Revenue Obligation Resolution, and of the Revenues, and of the income therefrom, with all such powers as the court or courts making such appointment shall confer, including the power to perform and enforce all contracts, to the same extent that the Authority shall then be entitled and obligated to do; provided, however, that, notwithstanding the happening of an Event of Default, the rights and obligations of the parties to such contracts not in default shall not be affected by such happening of an Event of Default. Notwithstanding the appointment of any receiver, the Trustee shall be entitled to retain possession and control of and to collect and receive income from any moneys, securities, funds and Revenues deposited or pledged with it under the Revenue Obligation Resolution or agreed or provided to be delivered to or deposited or pledged with it under the Revenue Obligation Resolution.

Suits by Individual Owners

No holder of any of the Obligations shall have any right to institute any suit, action or proceeding in equity or at law for the enforcement of any provision of the Revenue Obligation Resolution or the execution of any trust under the Revenue Obligation Resolution or for any remedy under the Revenue Obligation Resolution unless such holder previously shall have given to the Trustee written notice of the Event of Default, on account of which such suit, action or proceeding is to be instituted, and unless, also, the holders of not less than 25% in aggregate principal amount of the Obligations then Outstanding shall have filed a written request with the Trustee after the right to exercise such powers or right of action, as the case may be, shall have accrued, and unless, also, there shall have been offered to the Trustee reasonable security and indemnity against the costs, expenses and liabilities to be incurred therein or thereby, and the Trustee for a period of 60 days after the receipt by it of such notice, request and offer to indemnify shall have failed to proceed to exercise such powers or to institute any such action, suit or proceeding, and no direction inconsistent with such written request shall have been given to the Trustee pursuant the Revenue Obligation Resolution; it being understood and intended that, except as otherwise above provided, no one or more holders of the Obligations shall have any right in any manner whatsoever by his or their action to affect, disturb or prejudice the pledge created by the Revenue Obligation Resolution, or to enforce any right under the Revenue Obligation Resolution except in the manner herein provided and that all proceedings at law or in equity shall be instituted, had and maintained in the manner herein provided for the benefit of holders of such Revenue Outstanding Obligations.In the event that the Trustee shall have failed or refused to comply with the aforesaid request after having been offered such security and indemnity, the holders of not less than 20% in principal amount of the Obligations then Outstanding may call a meeting of the holders of Obligations for the purpose of electing an Owners' Committee. At such meeting the holders of not less than a majority of the principal amount of the Obligations then Outstanding must be present in person or by proxy in order to constitute a quorum for the transaction of business, less than a quorum, however, having power to adjourn from time to time without any other notice than the announcement thereof at the meeting. A quorum being present at the meeting, the holders of Obligations present in person or by proxy may, by the votes cast by the holders of a majority in principal amount of the Obligations so present in person or by proxy, elect one or more persons who may or may not be holders of Obligations to the Owners' Committee which shall act as trustee for all holders of Obligations. The holders of Obligations present in person or by proxy at such meeting, or at any adjourned meeting thereof, shall prescribe the manner in which the successors of the persons elected to the Owners' Committee at such meeting shall be elected or appointed, and may prescribe rules and regulations governing the exercise by the Owners' Committee of the powers conferred upon it in the Revenue Obligation Resolution, and may provide for the termination of the existence of the Owners' Committee. The Owners' Committee may, with the consent of the holders of more than 50% of the principal amount of Obligations Outstanding, remove the Trustee.

Nothing in the Revenue Obligation Resolution or in the Obligations shall affect or impair the obligation of the Authority to pay at the respective dates of maturity and places therein expressed the principal of and premium, if any, and interest on the Obligations to the respective holders thereof in accordance with the terms and conditions thereof and of the Revenue Obligation Resolution, or affect or impair the rights of action, which are absolute and unconditional, of any holder to enforce the payment of his Obligations in accordance with the terms and conditions thereof and of the Revenue Obligation Resolution, or to institute action upon and reduce to judgment his claim against the Authority for the payment of the principal and interest on his Obligations, without reference to, or consent of, the Trustee or any other holder of Obligations.

Notice of Events of Default

The Trustee shall, within 90 days after the occurrence of an Event of Default, give to the holders of Obligations notice of all defaults known to the Trustee, unless such defaults shall have been cured before the giving of such notice; provided that, except in the case of default in the payment of principal (whether at maturity or date of mandatory redemption) of and premium, if any, and interest on any of the Obligations, the Trustee shall be protected in withholding such notice if and so long as its board of directors, the executive committee, or a trust committee in good faith determines that the withholding of such notice is in the interests of the holders of Obligations.

Owners' Meetings

The Authority, the Trustee or the holders of not less than 20% in principal amount of the Obligations then Outstanding may at any time call a meeting of the holders of the Obligations. Every such meeting shall be held at such place as may be specified in the notice calling such meeting. Written notice of such meeting, stating the place and time of the meeting and in general terms the business to be submitted, shall be mailed to the holders of Obligations by the Authority, the Trustee or the holders of Obligations calling. The procedures and other provisions relating to such Owner's meeting and Owner's Committee are set forth in the Revenue Obligation Resolution.

Modifications of the Revenue Obligation Resolution

Modifications of the Revenue Obligation Resolution and of the rights and duties of the Authority and the holders of Obligations may be made with the consent of the Authority and written consent of the holders of not less than a majority of the Obligations at the time outstanding; provided that no modification shall be made which will (i) extend the fixed maturity date for the payment of any Obligation, or reduce the principal amount of or interest rate on any such Obligation or extend the time of payment of interest thereon or reduce any premium payable upon the prepayment or redemption thereof, or advance the date upon which any Obligation may first be called for redemption; or (ii) reduce the percentage of Obligations the holders of which are required to consent to any amendment to the Revenue Obligation Resolution; or (iii) give any Obligation or Obligations any preference over any other Obligation or Obligations or reduce the payments required to be made to the Revenue Obligation Fund, without the consent of the holders of all the Obligations affected thereby.

Defeasance

The obligations of the Authority under the Revenue Obligation Resolution shall be fully discharged and satisfied as to any Obligation and such Obligation shall no longer be deemed to be outstanding thereunder when payment of the principal of and the applicable redemption premium, if any, on such Obligation plus interest to the due date thereof (a) shall have been made or caused to be made in accordance with the terms thereof, or (b) shall have been provided by irrevocably depositing with the Trustee therefor in trust irrevocably appropriated and set aside exclusively for such payment (i) moneys sufficient to make such payments or (ii) Permitted Investments, maturing as to principal and interest in such amounts and at such times as will insure the availability of sufficient moneys to make such payment, and, except for the purposes of such payment, such Obligation shall no longer be secured by or entitled to the benefits of the Revenue Obligation Resolution; provided that, with respect to Obligations to be redeemed or otherwise prepaid prior to the stated maturities thereof, notice of such redemption or prepayment shall have been given or irrevocable provision shall have been made for the giving of such notice.

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APPENDIX C

PROVISIONS FOR BOOK-ENTRY ONLY SYSTEM

The information set forth in this APPENDIX C concerning DTC and DTC's book-entry system is subject to any change in or reinterpretation of the rules, regulations and procedures of DTC currently in effect. The information in this APPENDIX C concerning DTC has been obtained from sources that the Authority believes to be reliable. No representation is made herein by the Authority or the Underwriters as to the accuracy, completeness or adequacy of such information, or as to the absence of material adverse changes in such information subsequent to the date of this Official Statement. The Authority will not have any responsibility or liability for any aspect of the records relating to, or payments made on account of beneficial ownership interests in the 2026 Bonds held through the facilities of DTC or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests.

So long as Cede & Co. is the registered owner of the 2026 Bonds, as nominee for DTC, references herein and in the Revenue Obligation Resolution to the Holders, Bondholders, registered owners or owners (or similar terms) of the 2026 Bonds shall mean Cede & Co., as aforesaid, and shall not mean the Beneficial Owners of the 2026 Bonds.

DTC Book-Entry-Only System

The Depository Trust Company, Brooklyn, New York ("DTC"), will act as securities depository for the 2026 Bonds. The 2026 Bonds will be issued initially as fully-registered 2026 Bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully registered Bond will be issued for each maturity of each Series of the 2026 Bonds, each in the aggregate principal amount of such maturity, and will be deposited with DTC.

Beneficial ownership interests in the 2026 Bonds will be available only in book-entry form. Beneficial Owners of the 2026 Bonds ("Beneficial Owners") will not receive physical bond certificates representing their interests in the 2026 Bonds purchased. So long as DTC or its nominee is the registered owner of the 2026 Bonds, references in this Official Statement to the Owners of the 2026 Bonds shall mean DTC or its nominee and shall not mean the Beneficial Owners.

THE FOLLOWING DESCRIPTION OF DTC, ITS PROCEDURES AND RECORD KEEPING ON BENEFICIAL OWNERSHIP INTERESTS IN THE 2026 BONDS, PAYMENT OF INTEREST AND OTHER PAYMENTS ON THE 2026 BONDS TO DTC PARTICIPANTS (AS HEREIN DEFINED) OR TO BENEFICIAL OWNERS, CONFIRMATION AND TRANSFER OF BENEFICIAL OWNERSHIP INTERESTS IN THE 2026 BONDS AND OF OTHER TRANSACTIONS BY AND BETWEEN DTC, DTC PARTICIPANTS AND BENEFICIAL OWNERS IS BASED ON INFORMATION FURNISHED BY DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended. DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments (from over 100 countries) that DTC's participants (*"Direct Participants"*) deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of certificated 2026 Bonds. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations. DTC is a wholly owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants"). DTC has an S&P rating of AA+. The DTC Rules applicable to its Participants are on file with the Securities and Exchange Commission. More information about DTC can be found at www.dtcc.com.

Purchases of the 2026 Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the 2026 Bonds on DTC's records. The ownership interest of each actual purchaser of the 2026 Bonds ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchases. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of beneficial ownership interests in the 2026 Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the 2026 Bonds, except in the event that use of the book-entry only system for the 2026 Bonds is discontinued.

To facilitate subsequent transfers, all of the 2026 Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of the 2026 Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the 2026 Bonds. DTC's records reflect only the identity of the Direct Participants to whose accounts such 2026 Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time. Beneficial Owners of the 2026 Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the 2026 Bonds, such as redemptions, tenders, defaults, and proposed amendments to the 2026 Bond documents. For example, Beneficial Owners of the 2026 Bonds may wish to ascertain that the nominee holding the 2026 Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the 2026 Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in the 2026 Bonds to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the 2026 Bonds unless authorized by a Direct Participant in accordance with DTC's MMI Procedures. Under its usual procedures, DTC mails an omnibus proxy to the Registrar as soon as possible after the record date. The omnibus proxy assigns Cede & Co.'s consenting and voting rights to those Direct Participants to whose accounts the 2026 Bonds are credited on the record date (identified in a listing attached to the omnibus proxy).

Redemption proceeds, principal, and interest payments on the 2026 Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detail information from the Trustee, on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC (nor its nominee), the Registrar or the Authority, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds, principal, and interest payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the Paying Agent's responsibility, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners shall be the responsibility of Direct and Indirect Participants. THE AUTHORITY CAN GIVE NO ASSURANCE THAT DIRECT AND INDIRECT PARTICIPANTS WILL PROMPTLY TRANSFER PAYMENTS TO BENEFICIAL OWNERS.

A Beneficial Owner shall give notice to elect to have its 2026 Bonds purchased or tendered, through its Participant, to the Registrar and Paying Agent, and shall effect delivery of such 2026 Bonds by causing the Direct Participant to transfer the Participant's interest in the 2026 Bonds, on DTC's records, to the Registrar and Paying Agent. The requirement for physical delivery of the 2026 Bonds in connection with an optional tender or a mandatory purchase will be deemed satisfied when the ownership rights in the 2026 Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered 2026 Bonds to the Registrar and Paying Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the 2026 Bonds any time by giving reasonable notice to the Authority or the Paying Agent. Under such circumstances, in the event that a successor securities depository is not obtained, 2026 Bond certificates are required to be printed and delivered.

The Authority may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository). In such event, 2026 Bond certificates will be printed and delivered.

THE AUTHORITY AND THE REGISTRAR AND PAYING AGENT HAVE NO RESPONSIBILITY OR OBLIGATION TO THE PARTICIPANTS OR THE BENEFICIAL OWNERS WITH RESPECT TO (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY PARTICIPANT, OR THE MAINTENANCE OF ANY RECORDS; (2) THE PAYMENT BY DTC OR ANY PARTICIPANT OF ANY AMOUNT DUE TO ANY BENEFICIAL OWNER IN RESPECT OF THE 2026 BONDS, OR THE SENDING OF ANY TRANSACTION STATEMENTS; (3) THE DELIVERY OR TIMELINESS OF DELIVERY BY DTC OR ANY PARTICIPANT OF ANY NOTICE TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED UNDER THE RESOLUTION AUTHORIZING THE ISSUANCE OF SUCH 2026 BONDS TO BE GIVEN TO OWNERS; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENTS UPON ANY PARTIAL REDEMPTION OF THE 2026 BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC OR ITS NOMINEE AS THE REGISTERED OWNER OF THE 2026 BONDS, INCLUDING ANY ACTION TAKEN PURSUANT TO AN OMNIBUS PROXY.

THE INFORMATION IN THIS SECTION CONCERNING DTC AND DTC'S BOOK-ENTRY SYSTEM HAS BEEN OBTAINED FROM SOURCES THAT THE AUTHORITY BELIEVES TO BE RELIABLE, BUT THE AUTHORITY TAKES NO RESPONSIBILITY FOR THE ACCURACY THEREOF.

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APPENDIX D

CERTAIN ECONOMIC AND DEMOGRAPHIC INFORMATION

State of South Carolina Economy

The Authority's customers and energy sales are supported by the general economic activity and demographic makeup of South Carolina. This section presents information regarding certain economic and demographic information about the State. This data is intended only to provide prospective investors with general information regarding the State's economy. The information was obtained from the sources indicated and is limited to the time periods indicated. The information is historic in nature; it is not possible to predict whether the trends shown will continue in the future. Although the Authority considers the sources to be reliable, the Authority has made no independent verification of the information provided by non-Authority sources and does not warrant its accuracy.

The 2026 Bonds and other indebtedness of the Authority are not indebtedness of the State, nor any political subdivision thereof, and neither the State not any political subdivision thereof shall be liable thereon, nor shall they be payable from any funds other than the Revenues of the Authority pledged to the payment thereof.

In 2024, the principal contributors to the State's gross domestic product were finance, insurance, real estate, rental, and leasing (20.7%) and manufacturing (13.3%), followed by government and government enterprises (12.9%). During the years 2023-2024, the biggest contributors to the growth in the State's gross domestic product were retail trade (1.13 percentage point of the total growth in real GDP), finance, insurance, real estate, rental, and leasing (0.89 percentage point of the total growth in real GDP) and manufacturing (0.48 percentage point of the total growth in real GDP). The State's total gross domestic product grew at a compound annual growth rate of 4.5% versus 4.3% for southeastern states, and 3.6% for the nation from 2019-2023. The table below provides the State's Real Gross Domestic Product for years 2020 through 2024.

Year	Total GDP ($ in millions)
2020	$248,952.7
2021	272,464.9
2022	305,070.0
2023	332,946.8
2024	357,074.4

Source: *U.S. Department of Commerce, Bureau of Economic Analysis.*

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Personal Income. In 2024, the State's per capital personal income increased to $60,776 or 5.2% over 2023, compared to increases of 4.8% for southeastern states and 4.6% for the nation. The State's per capita personal income in 2024 was 83% of the national per capita personal income (compared to 82.5% in 2023) and 91.7% of the Southeast (compared to 96.1% in 2023). The following table sets forth information on personal income (expressed in millions) for the State since 2013.

Year	**Total Personal Income**	**Per Capita Personal Income**
2013	$ 170,204.8	$ 35,923
2014	180,837.7	37,755
2015	192,054.7	39,598
2016	200,027.4	40,752
2017	210,387.6	42,385
2018	219,942.1	43,817
2019	234,295.4	46,150
2020	250,250.5	48,760
2021	277,322.6	53,390
2022	288,512.6	54,561
2023	311,235.5	57,766
2024	332,982.7	60,776

Source: *U.S. Department of Commerce, Bureau of Economic Analysis.*

Population. The State's population estimate in 2024 was 5,478,831, or 1.7% over 2023, compared to increases of 1.2% for the South and 1.0% for the nation. The table below shows the population estimates (expressed in thousands) of the State since 2013.

Year	**Population**
2013	4,738
2014	4,789
2015	4,850
2016	4,908
2017	4,963
2018	5,019
2019	5,076
2020	5,132
2021	5,194
2022	5,287
2023	5,387
2024	5,478

Source: *U.S. Census Bureau.*

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Employment. Over the period from 2014 to 2024, the compounded annual employment growth rate in South Carolina was higher than in the Southeast and the nation. The table below shows the (seasonally adjusted) nonfarm employment in South Carolina, the Southeast and the United States for such period.

	Employment (in thousands)		**Compounded Annual Growth**
	2014	**2024**	**2014-2024**
South Carolina	2,564	3,205	2.3%
Southeast	45,200	55,604	2.1%
United States	186,239	218,181	1.6%

Source: *U.S. Department of Commerce, Bureau of Labor Statistics.*

The State's (seasonally adjusted) nonfarm employment increased 2.0% from November 2024 to November 2025. The trade, transportation and utilities sector is the largest employment sector in South Carolina as of November 2025, accounting for 18.8% of the State's nonfarm employment, which was the same percentage as in November 2014. In November 2025, the State's (seasonally adjusted) nonfarm employment level reached 2,424,800 people employed.

From November 2024 to November 2025, the State's economy has gained 48,400 (seasonally adjusted) nonfarm jobs. Industries with strong growth were reported in leisure and hospitality (+15,500); education and health services (+9,000); trade, transportation, and utilities (+8,800); professional and business services (+8,300); financial activities (+2,900); information (+2,200) and other services (+2,000); while manufacturing (–2,500) had a negative change of 1.0% from November 2024.

The State's (seasonally adjusted) unemployment rate was 4.4% in November 2024 and is 4.6% as of November 2025, an increase of 0.2%. Twenty-eight states and the District of Columbia had unemployment rate increases from November 2024, the largest of which was in Delaware. The table below shows the State's unemployment rate as of November since 2015.

Year	**Unemployment Rate**
2015	5.5%
2016	4.5
2017	4.2
2018	3.2
2019	2.5
2020	5.1
2021	4.0
2022	3.2
2023	3.2
2024	4.4
2025	4.6[1]

Source: *U.S. Department of Labor, Bureau of Labor Statistics.*
[1] Preliminary.

Customer Growth Initiatives

The Authority's business growth initiatives revolve around four strategic initiatives – marketing, product development, project management and competitive rates. The Authority is marketing to industrial and commercial properties that are served directly by the Authority and its cooperative and municipal customers. Product development activities include the creation and/or improvement of industrial properties, the acquisition of property, expansion of infrastructure into industrial properties, and/or constructing buildings for industrial uses. Since June 2012, the Authority has invested over $112 million throughout South Carolina in product development through a low-interest revolving loan pool to public entities. In addition, the Authority has utilized two additional funds to further improve the readiness of industrial sites in cooperative and municipal customers' territories, which have committed more than $46.7 million in local site investment since 2014.

In September 2015, Swedish automaker Volvo broke ground on its first plant in the United States in Berkeley County, South Carolina. Volvo began production in 2018 and announced a $520 million expansion with a second line that was scheduled to begin production by the end of 2022 and add approximately 1,900 new jobs. Volvo completed the plant expansion and began production of the all-electric EX90. Additionally, Volvo began to build the Polestar 3 under contract with its affiliate, Polestar Cars. Polestar Cars is the Swedish electric performance brand launched by Volvo and Geely Holding in 2017. Meanwhile, production of the S60 was phased out in anticipation of producing better selling Volvo models for the US market. Starting in 2026, Volvo plans to increase production of its most popular SUV in America, the XC60, at the plant. Volvo is also planning to launch a new next-generation hybrid vehicles designed for American drivers, which are expected to be in production at the plant before 2030. Volvo, Polestar, and Geely continue to adjust production and models to address various markets and supply chain conditions.

The Authority worked with the State, Berkeley County, and the electric cooperatives to recruit Volvo to this site. Water for the plant comes from the Authority's Lake Moultrie Regional Water System via Berkeley County Water and Sanitation, and Edisto Electric Cooperative, one of the Central Cooperatives, delivers electric power to the plant. The Authority owns approximately 3,900 acres adjacent to the Volvo site. The Authority has master planned this property named Camp Hall to be a world class industrial park to serve Volvo suppliers and other industries.

On April 10, 2024, the Authority released a comprehensive impact study on Camp Hall, detailing the environmentally focused industrial park's significant economic influence and additional potential for growth. The study puts Camp Hall's current annual economic impact at $3.8 billion across South Carolina and $3.4 billion in the Charleston tri-county region.

The Authority's grant and loan programs with addition to competitive rates have facilitated the location of other recent notable projects around the State. These projects include Nucor Corporation expansion in Berkeley County with $625 million in capital investment and 50 new jobs, RL Cold with $90 million in capital investment and 100 new jobs, DC Box in the City of Myrtle Beach with $31 million in capital investment, and Redwood Materials with $3.5 billion capital investment and 1,500 new jobs.

In July 2025, it was announced that Camp Hall Commerce Park has been named the No. 1 industrial park in the nation in Business Facilities Magazine's 21st Rankings Report, the magazine's annual assessment of economic development and location leaders. Camp Hall, which is being developed by the Authority, has been in the magazine's top 10 for six years in a row.

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APPENDIX E

PROPOSED FORMS OF BOND COUNSEL OPINION

Proposed Form of Opinion for the Tax-Exempt Bonds

__________, 2026

Board of Directors
South Carolina Public Service Authority
One Riverwood Drive
Moncks Corner, South Carolina 29461

Re: $__________ South Carolina Public Service Authority Revenue Obligations, 2026 Tax-Exempt Improvement Series A
$__________ South Carolina Public Service Authority Revenue Obligations, 2026 Tax-Exempt Refunding Series C

We have acted as bond counsel to South Carolina Public Service Authority (the "Authority") in connection with the issuance of $__________ South Carolina Public Service Authority Revenue Obligations, 2026 Tax-Exempt Improvement Series A (the "2026A Bonds"), and $__________ South Carolina Public Service Authority Revenue Obligations, 2026 Tax-Exempt Refunding Series C, each dated __________, 2026 (the "2026C Bonds", and together with the 2026A Bonds, the "2026 Bonds"). In such capacity, we have examined such law and such certified proceedings, certifications, and other documents as we have deemed necessary to render the opinions below.

The 2026 Bonds are issued pursuant to Title 58, Chapter 31, Code of Laws of South Carolina 1976, as amended, a resolution of the Authority's Board of Directors (the "Board") adopted April 26, 1999 entitled: "RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY ESTABLISHING THE GENERAL TERMS AND CONDITIONS UPON WHICH ITS REVENUE OBLIGATIONS MAY BE ISSUED FOR CORPORATE PURPOSES OF THE AUTHORITY", as amended and supplemented from time to time, unless the context shall clearly indicate otherwise (the "Master Resolution"), a "SIXTY-FOURTH SERIES AND SUPPLEMENTAL RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY SUPPLEMENTING A RESOLUTION OF THE SAID BOARD OF DIRECTORS ADOPTED APRIL 26, 1999 ENTITLED: "RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY ESTABLISHING THE GENERAL TERMS AND CONDITIONS UPON WHICH ITS REVENUE OBLIGATIONS MAY BE ISSUED FOR CORPORATE PURPOSES OF THE AUTHORITY" AND AUTHORIZING THE ISSUANCE OF $__________ SOUTH CAROLINA PUBLIC SERVICE AUTHORITY REVENUE OBLIGATIONS, 2026 TAX-EXEMPT IMPROVEMENT SERIES A, PURSUANT AND SUBJECT TO THE TERMS, CONDITIONS AND LIMITATIONS OF THE SAID RESOLUTION" adopted by the Board on __________, 2026 (the "Sixty-Fourth Supplemental Resolution"), a "SIXTY-SIXTH SERIES AND SUPPLEMENTAL RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY SUPPLEMENTING A RESOLUTION OF THE SAID BOARD OF DIRECTORS ADOPTED APRIL 26, 1999 ENTITLED: "RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY ESTABLISHING THE GENERAL TERMS AND CONDITIONS UPON WHICH ITS REVENUE OBLIGATIONS MAY BE ISSUED FOR CORPORATE PURPOSES OF THE AUTHORITY" AND AUTHORIZING THE ISSUANCE OF $__________ SOUTH CAROLINA PUBLIC SERVICE AUTHORITY REVENUE

OBLIGATIONS, 2026 TAX-EXEMPT REFUNDING SERIES C, PURSUANT AND SUBJECT TO THE TERMS, CONDITIONS AND LIMITATIONS OF THE SAID RESOLUTION" adopted by the Board on __________, 2026 (the "Sixty-Sixth Supplemental Resolution", and together with the Sixty-Fourth Supplemental Resolution and the Master Resolution, the "Resolution"). All capitalized terms used herein and not defined shall have the meaning ascribed to such terms in the Resolution.

Regarding questions of fact material to the opinions below, we have relied on the representations of the Authority contained in the Resolution, and in the certified proceedings and other certifications of representatives of the Authority and certificates of others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

1. The Authority is validly existing as a body corporate and politic of the State of South Carolina with the power to adopt the Resolution, perform the agreements on its part contained therein, and issue the 2026 Bonds.

2. The Resolution has been duly adopted by the Authority, and constitutes a valid and binding obligation of the Authority.

3. The Resolution creates a valid lien on the Revenues for the security of the 2026 Bonds on a parity with other bonds (if any) issued or to be issued under the Resolution of similar lien priority.

4. The 2026 Bonds have been duly authorized and executed by the Authority, and are valid and binding limited obligations of the Authority, payable solely from the Revenues and other funds provided therefor in the Resolution.

5. Interest on the 2026 Bonds is excludable from gross income for federal income tax purposes under Section 103 of the Internal Revenue Code of 1986, as amended (the "Code"), and is not an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals; however, such interest on the 2026 Bonds may be taken into account for the purpose of computing the alternative minimum tax imposed on certain corporations. The opinion set forth in the preceding sentence is subject to the condition that the Authority comply with all requirements of the Code that must be satisfied subsequent to the issuance of the 2026 Bonds in order that the interest thereon be, and continue to be, excludable from gross income for federal income tax purposes under Section 103 of the Code. The Authority has covenanted to comply with all such requirements. Failure to comply with certain of such requirements may cause interest on the 2026 Bonds to be includable in gross income for federal income tax purposes retroactively to the date of issuance of the 2026 Bonds.

6. It is also our opinion that, under existing laws of the State of South Carolina, the 2026 Bonds and the interest thereon are presently exempt from all taxation in said State or any political subdivision thereof, except estate or other transfer taxes and certain franchise taxes. It should be noted, however, that Section 12-11-20, Code of Laws of South Carolina 1976, as amended, imposes upon every bank engaged in business in the State a fee or franchise tax computed on the entire net income of such bank which includes interest paid on the 2026 Bonds.

The rights of the owners of the 2026 Bonds and the enforceability of the 2026 Bonds and the Resolution are limited by bankruptcy, insolvency, reorganization, moratorium, and other similar laws affecting the rights and remedies of creditors, and by equitable principles, whether considered at law or in equity.

We express no opinion regarding the accuracy, adequacy, or completeness of the Official Statement relating to the 2026 Bonds, or regarding the attachment, perfection or priority of the lien on Revenues or other funds created by the Resolution. Further, we express no opinion herein regarding tax consequences arising with respect to the 2026 Bonds other than as expressly set forth herein.

The opinions given in this opinion letter are given as of the date set forth above, and we assume no obligation to revise or supplement them to reflect any facts or circumstances that may later come to our attention, or any changes in law that may later occur.

Very truly yours,

BURR & FORMAN LLP

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Proposed Form of Opinion for the Taxable Bonds

__________, 2026

Board of Directors
South Carolina Public Service Authority
One Riverwood Drive
Moncks Corner, South Carolina 29461

Re: $__________ South Carolina Public Service Authority Revenue Obligations, 2026 Taxable Improvement Series B

We have acted as bond counsel to South Carolina Public Service Authority (the "Authority") in connection with the issuance of $__________ South Carolina Public Service Authority Revenue Obligations, 2026 Taxable Improvement Series B, dated __________, 2026 (the "2026B Bonds"). In such capacity, we have examined such law and such certified proceedings, certifications, and other documents as we have deemed necessary to render the opinions below.

The 2026B Bonds are issued pursuant to Title 58, Chapter 31, Code of Laws of South Carolina 1976, as amended, a resolution of the Authority's Board of Directors (the "Board") adopted April 26, 1999 entitled: "RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY ESTABLISHING THE GENERAL TERMS AND CONDITIONS UPON WHICH ITS REVENUE OBLIGATIONS MAY BE ISSUED FOR CORPORATE PURPOSES OF THE AUTHORITY", as amended and supplemented from time to time, unless the context shall clearly indicate otherwise (the "Master Resolution"), and a "SIXTY-FIFTH SERIES AND SUPPLEMENTAL RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY SUPPLEMENTING A RESOLUTION OF THE SAID BOARD OF DIRECTORS ADOPTED APRIL 26, 1999 ENTITLED: "RESOLUTION OF THE BOARD OF DIRECTORS OF SOUTH CAROLINA PUBLIC SERVICE AUTHORITY ESTABLISHING THE GENERAL TERMS AND CONDITIONS UPON WHICH ITS REVENUE OBLIGATIONS MAY BE ISSUED FOR CORPORATE PURPOSES OF THE AUTHORITY" AND AUTHORIZING THE ISSUANCE OF $__________ SOUTH CAROLINA PUBLIC SERVICE AUTHORITY REVENUE OBLIGATIONS, 2026 TAXABLE IMPROVEMENT SERIES B, PURSUANT AND SUBJECT TO THE TERMS, CONDITIONS AND LIMITATIONS OF THE SAID RESOLUTION" adopted by the Board on __________, 2026 (the "Sixty-Fifth Supplemental Resolution", together with the Master Resolution, the "Resolution"). All capitalized terms used herein and not defined shall have the meaning ascribed to such terms in the Resolution.

Regarding questions of fact material to the opinions below, we have relied on the representations of the Authority contained in the Resolution, and in the certified proceedings and other certifications of representatives of the Authority and certificates of others furnished to us without undertaking to verify the same by independent investigation.

Based on the foregoing, we are of the opinion that, under existing law:

1. The Authority is validly existing as a body corporate and politic of the State of South Carolina with the power to adopt the Resolution, perform the agreements on its part contained therein, and issue the 2026B Bonds.

2. The Resolution has been duly adopted by the Authority, and constitutes a valid and binding obligation of the Authority.

3. The Resolution creates a valid lien on the Revenues for the security of the 2026B Bonds on a parity with other bonds (if any) issued or to be issued under the Resolution of similar lien priority.

4. The 2026B Bonds have been duly authorized and executed by the Authority, and are valid and binding limited obligations of the Authority, payable solely from the Revenues and other funds provided therefor in the Resolution.

5. It is also our opinion that, under existing laws of the State of South Carolina, the 2026B Bonds and the interest thereon are presently exempt from all taxation in said State or any political subdivision thereof, except estate or other transfer taxes and certain franchise taxes. It should be noted, however, that Section 12-11-20, Code of Laws of South Carolina 1976, as amended, imposes upon every bank engaged in business in the State a fee or franchise tax computed on the entire net income of such bank which includes interest paid on the 2026B Bonds.

The rights of the owners of the 2026B Bonds and the enforceability of the 2026B Bonds and the Resolution are limited by bankruptcy, insolvency, reorganization, moratorium, and other similar laws affecting the rights and remedies of creditors, and by equitable principles, whether considered at law or in equity.

We express no opinion regarding the accuracy, adequacy, or completeness of the Official Statement relating to the 2026B Bonds, or regarding the attachment, perfection or priority of the lien on Revenues or other funds created by the Resolution. Further, we express no opinion herein regarding tax consequences arising with respect to the 2026B Bonds other than as expressly set forth herein.

The opinions given in this opinion letter are given as of the date set forth above, and we assume no obligation to revise or supplement them to reflect any facts or circumstances that may later come to our attention, or any changes in law that may later occur.

Very truly yours,

BURR & FORMAN LLP

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APPENDIX F

PROPOSED FORM OF CONTINUING DISCLOSURE AGREEMENT

This Continuing Disclosure Agreement (the "Disclosure Agreement") is executed and delivered as of the ___ day of _________, 2026, by and between SOUTH CAROLINA PUBLIC SERVICE AUTHORITY (the "Authority"), and THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A. (the "Obligation Fund Trustee"), in connection with the issuance by the Authority of (i) its $__________ Revenue Obligations, 2026 Tax-Exempt Improvement Series A (the "2026A Bonds"), pursuant to a resolution adopted by the Board of Directors of the Authority on April 26, 1999, as supplemented and amended from time to time, including as supplemented by the Sixty-Fourth Series and Supplemental Resolution adopted by the Board of Directors of the Authority on __________, 2026, (ii) its $__________ Revenue Obligations, 2026 Taxable Improvement Series B (the "2026B Bonds"), pursuant to a resolution adopted by the Board of Directors of the Authority on April 26, 1999, as supplemented and amended from time to time, including as supplemented by the Sixty-Fifth Series and Supplemental Resolution adopted by the Board of Directors of the Authority on __________, 2026, and (iii) its $__________ Revenue Obligations, 2026 Tax-Exempt Refunding Series C (the "2026C Bonds" and together with the 2026A Bonds and the 2026B Bonds, the "2026 Bonds"), pursuant to a resolution adopted by the Board of Directors of the Authority on April 26, 1999, as supplemented and amended from time to time, including as supplemented by the Sixty-Sixth Series and Supplemental Resolution adopted by the Board of Directors of the Authority on __________, 2026 (collectively, the "Revenue Obligation Resolution"). The Authority and the Obligation Fund Trustee covenant and agree as follows:

SECTION 1. Purpose of the Disclosure Agreement. This Disclosure Agreement is being executed and delivered by the Authority and the Obligation Fund Trustee for the benefit of the Holders and Beneficial Owners of the 2026 Bonds and in order to assist the Participating Underwriters in complying with S.E.C. Rule 15c2-12(b)(5).

SECTION 2. Definitions. In addition to the definitions set forth in the Revenue Obligation Resolution, which apply to any capitalized term used in this Disclosure Agreement unless otherwise defined in this Section, the following capitalized terms shall have the following meanings:

"Annual Report" shall mean any Annual Report provided by the Authority pursuant to, and as described in, Sections 3 and 4 of this Disclosure Agreement.

"Beneficial Owner" shall mean any person which (a) has the power, directly or indirectly, to vote or consent with respect to, or to dispose of ownership of, any 2026 Bonds (including persons holding 2026 Bonds through nominees, depositories or other intermediaries), or (b) is treated as the owner of any 2026 Bonds for federal income tax purposes.

"Disclosure Representative" shall mean the Treasurer of the Authority or his or her designee, or such other officer or employee as the Authority shall designate in writing to the Obligation Fund Trustee from time to time.

"Dissemination Agent" shall mean any Dissemination Agent designated in writing by the Authority and which has filed with the Obligation Fund Trustee a written acceptance of such designation.

"Listed Events" shall mean any of the events listed in Section 5(a) of this Disclosure Agreement.

"National Repository" shall mean the Municipal Securities Rulemaking Board through its Electronic Municipal Market Access ("EMMA") System at www.emma.msrb.org, or any successor National Repository as determined by the Securities and Exchange Commission.

"Participating Underwriters" shall mean J.P. Morgan Securities LLC, BofA Securities, Inc., Barclays Capital Inc., Academy Securities, Inc., Goldman Sachs & Co. LLC, TD Financial Products LLC, Truist Securities, Inc. and Wells Fargo Bank, National Association, which are the original underwriters of the 2026 Bonds and are required to comply with the Rule in connection with the offering of the 2026 Bonds.

"Repository" shall mean each National Repository and each State Repository.

"Rule" shall mean Rule 15c2-12(b)(5) adopted by the Securities and Exchange Commission under the Securities Exchange Act of 1934, as in effect as of the date hereof.

"State" shall mean the State of South Carolina.

"State Repository" shall mean any public or private repository or entity designated by the State as a state repository for the purposes of the Rule and recognized as such by the Securities and Exchange Commission. As of the date of execution of this Disclosure Agreement, there is no State Repository.

SECTION 3. Provision of Annual Reports.

(a) The Authority shall provide, or shall cause the Dissemination Agent to provide, not later than six months after the end of the Authority's fiscal year (presently December 31), commencing with the fiscal year ending December 31, 2025, to each Repository an Annual Report which is consistent with the requirements of Section 4 of this Disclosure Agreement. The Annual Report may be submitted as a single document or as separate documents comprising a package, and may include by reference other information as provided in Section 4 of this Disclosure Agreement; provided that the audited financial statements of the Authority may be submitted separately from the balance of the Annual Report and later than the date required above for the filing of the Annual Report if they are not available by that date. If the Authority's fiscal year changes, it shall give notice of such change in the same manner as for a Listed Event under Section 5 of this Disclosure Agreement.

(b) Not later than fifteen Business Days prior to the date specified in subsection (a) for providing the Annual Report to Repositories, the Authority shall provide the Annual Report to any Dissemination Agent and the Obligation Fund Trustee (if the Obligation Fund Trustee is not the Dissemination Agent). If by such date, the Obligation Fund Trustee has not received a copy of the Annual Report, the Obligation Fund Trustee shall contact the Authority and any Dissemination Agent to determine if the Authority is in compliance with the provisions of subsection (a) above.

(c) If the Obligation Fund Trustee is unable to verify that an Annual Report has been provided to Repositories by the date required in subsection (a), the Obligation Fund Trustee shall send a notice to the National Repository and to the State Repository, if any, in substantially the form attached as Exhibit A.

(d) Any Dissemination Agent shall:

(i) determine each year prior to the date for providing the Annual Report the name and address of the National Repository and the State Repository, if any; and

(ii) file a report with the Authority and (if the Dissemination Agent is not the Obligation Fund Trustee) the Obligation Fund Trustee certifying that the Annual Report has been provided pursuant to this Disclosure Agreement, stating the date it was provided and listing all the Repositories to which it was provided.

SECTION 4. Content of Annual Reports. The Authority's Annual Report shall contain or include by reference the following:

(a) the audited financial statements of the Authority for the prior fiscal year, prepared substantially in accordance with generally accepted accounting principles as promulgated to apply to governmental entities from time to time by the Governmental Accounting Standards Board, or such other accounting principles as the Authority may be required to employ from time to time pursuant to state law or regulation. If the Authority's audited financial statements are not available by the time the Annual Report is required to be filed pursuant to Section 3(a) of this Disclosure Agreement, the Annual Report shall contain unaudited financial statements in a format similar to the audited financial statements, and the audited financial statements shall be filed in the same manner as the Annual Report within fifteen days after they become available.

(b) to the extent such items are not included in the audited financial statements referred to in subsection (a) above, the financial and statistical data of the Authority as of a date not earlier than the end of the preceding fiscal year for the type of information included in the tables entitled "DEBT SERVICE REQUIREMENTS," "HISTORICAL SALES - Historical Demand, Sales, and Revenues," and "FINANCIAL INFORMATION - Historical Annual Operating Results" contained in the Official Statement of the Authority dated __________, 2026, prepared in connection with the issuance of the 2026 Bonds (the "Official Statement"), as well as information of the type contained in the Official Statement concerning: (A) the percentage of revenues from sales to (i) Central Electric Power Cooperative Inc., (ii) Century Aluminum of South Carolina, Inc., formerly Alumax of South Carolina, Inc. (iii) Nucor Corporation, (iv) the remaining eight largest industrial customers of the Authority, and (v) the remaining wholesale customers of the Authority; (B) the data set forth in the Official Statement under the caption "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES — Nuclear Generation" and (C) the data set forth in the Official Statement in the first paragraph under the caption "POWER SUPPLY, POWER MARKETING, PLANNING AND OTHER FACILITIES — Fuel Supply and Commodity Risk Management." Any or all of the items listed above may be included by specific reference to other documents, including official statements of debt issues of the Authority or related public entities, which have been submitted to each of the Repositories or the Securities and Exchange Commission. If the document included by reference is a final official statement, it must be available from the National Repository. The Authority shall clearly identify each such other document so included by reference.

SECTION 5. Reporting of Significant Events.

(a) The Authority shall give, or cause to be given, in a timely manner, to the National Repository and to the State Repository, if any, notice of the occurrence of any of the following events with respect to the 2026 Bonds, within 10 business days of the occurrence thereof:

1. principal and interest payment delinquencies;
2. non-payment related defaults, if material;
3. unscheduled draws on debt service reserves reflecting financial difficulties;
4. unscheduled draws on credit enhancements reflecting financial difficulties;
5. substitution of credit or liquidity providers, or their failure to perform;
6. adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB)

or other material notices or determinations with respect to the tax status of the 2026 Bonds, or other material events affecting the tax status of the 2026 Bonds;

7. modifications to the rights of Bondholders, if material;

8. Bond calls, if material, and tender offers;

9. defeasance of any of the 2026 Bonds;

10. release, substitution or sale of property securing repayment of the 2026 Bonds, if material;

11. rating changes;

12. bankruptcy, insolvency, receivership or similar event of the Authority;

13. the consummation of a merger, consolidation, or acquisition involving the Authority or the sale of all or substantially all of the assets of the Authority, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material;

14. appointment of a successor or additional trustee, or the change of name of a trustee, if material;

15. incurrence of a financial obligation[*] of the Authority, if material, or agreement to covenants, events of default, remedies, priority rights, or other similar terms of a financial obligation of the Authority, any of which affect Bondholders, if material; and

16. default, event of acceleration, termination event, modification of terms, or other similar events under the terms of a financial obligation[*] of the Authority, any of which reflect financial difficulties.

(b) The Obligation Fund Trustee shall, within three (3) business days of obtaining actual knowledge of the occurrence of any of the Listed Events, contact the Disclosure Representative, inform such person of the event, and request that the Authority promptly report the event or notify the Dissemination Agent in writing to report the event.

(c) Whenever the Authority obtains knowledge of the occurrence of a Listed Event, whether because of a notice from the Obligation Fund Trustee pursuant to subsection (b) or otherwise, the Authority shall promptly notify the Obligation Fund Trustee and the Dissemination Agent in writing. Such notice shall (i) instruct the Dissemination Agent to report the occurrence, or (ii) inform the Obligation Fund Trustee and the Dissemination Agent that the Authority shall report such occurrence.

SECTION 6. Termination of Reporting Obligation. The Authority's obligations under this Disclosure Agreement shall terminate upon the legal defeasance, prior redemption or payment in full of all of the 2026 Bonds. If such termination occurs prior to the final maturity of the 2026 Bonds, the Authority shall give notice of such termination in the same manner as for a Listed Event under Section 5 of this Disclosure Agreement.

[*] For purposes of the events identified in Sections 5(a)(15) and (16), the term "financial obligation" means a (i) debt obligation; (ii) derivative instrument entered into in connection with, or pledged as security or a source of payment for, an existing or planned debt obligation; or (iii) guarantee of (i) or (ii). The term "financial obligation" shall not include municipal securities as to which a final official statement has been provided to the National Repository consistent with the Rule.

SECTION 7. Notice of Failure to Provide Information. The Authority shall give, or cause to be given, in a timely manner, to the National Repository and to the State Repository, if any, notice of the failure to provide the Annual Report in the manner set forth in Sections 3 and 4 of this Disclosure Agreement.

SECTION 8. Dissemination Agent. The Authority may, from time to time, appoint or engage a Dissemination Agent to assist it in carrying out its obligations under this Disclosure Agreement, and may discharge any such Dissemination Agent, with or without appointing a successor Dissemination Agent. Neither the Dissemination Agent nor the Obligation Fund Trustee shall be responsible in any manner for the content of any notice or report (including, but not limited to, any Annual Report) prepared by the Authority pursuant to this Disclosure Agreement.

SECTION 9. Amendment; Waiver. Notwithstanding any other provision of this Disclosure Agreement, the Authority may amend this Disclosure Agreement (and the Obligation Fund Trustee shall agree to any evidence of such amendment requested in writing by the Authority), and any provision of this Disclosure Agreement may be waived, provided that the following conditions are satisfied:

(a) If the amendment or waiver relates to the provisions of Sections 3(a), 4, or 5(a) of this Disclosure Agreement, it may only be made in connection with a change in circumstances that arises from a change in legal requirements, change in law, or change in the identity, nature or status of an obligated person (as such term is defined in the Rule) with respect to the 2026 Bonds, or the type of business conducted;

(b) The undertaking, as amended or taking into account such waiver, would, in the opinion of nationally recognized bond counsel, have complied with the requirements of the Rule at the time of the original issuance of the 2026 Bonds, after taking into account any amendments or interpretations of the Rule, as well as any change in circumstances; and

(c) The amendment or waiver either (i) is approved by the Beneficial Owners of the 2026 Bonds in the same manner as provided in the Revenue Obligation Resolution for amendments to the Revenue Obligation Resolution with the consent of such Beneficial Owners, or (ii) does not, in the opinion of nationally recognized bond counsel, materially impair the interest of the Beneficial Owners of the 2026 Bonds.

In the event of any amendment or waiver of a provision of this Disclosure Agreement, the Authority shall describe such amendment in the next Annual Report, and shall include, as applicable, a narrative explanation of the reason for the amendment or waiver and its impact on the type (or, in the case of a change of accounting principles, on the presentation) of financial information or operating data being presented by the Authority. In addition, if the amendment relates to the accounting principles to be followed in preparing financial statements, (i) notice of such change shall be given in the same manner as for a Listed Event under Section 5 of this Disclosure Agreement, and (ii) the Annual Report for the year in which the change is made should present a comparison (in narrative form and also, if feasible, in quantitative form) between the financial statements as prepared on the basis of the new accounting principles and those prepared on the basis of the former accounting principles. Prior to executing any amendment to or waiver of this Disclosure Agreement, there shall be delivered to the Obligation Fund Trustee an opinion of counsel, upon which the Obligation Fund Trustee shall conclusively rely, to the effect that such amendment or waiver is authorized or permitted pursuant to the terms of Section 9 of this Disclosure Agreement.

SECTION 10. Additional Information. Nothing in this Disclosure Agreement shall be deemed to prevent the Authority from disseminating any other information, using the means of dissemination set forth in this Disclosure Agreement or any other means of communication, or including any other information in any Annual Report or notice of occurrence of a Listed Event, in addition to that which is required by this

Disclosure Agreement. If the Authority chooses to include any information in any Annual Report or notice of occurrence of a Listed Event in addition to that which is specifically required by this Disclosure Agreement, the Authority shall have no obligation under this Disclosure Agreement to update such information or include it in any future Annual Report or notice of occurrence of a Listed Event.

SECTION 11. Default. In the event of a failure of the Authority or the Obligation Fund Trustee to comply with any provision of this Disclosure Agreement, the Obligation Fund Trustee may (and, at the written request of the Participating Underwriters or the holders of at least 25% aggregate principal amount of Outstanding 2026 Bonds, and receiving indemnification satisfactory to the Obligation Fund Trustee, shall at the expense of the Authority), or any holder or Beneficial Owner of the 2026 Bonds may take such action and upon receiving indemnification satisfactory to the Obligation Fund Trustee as may be necessary and appropriate, including seeking mandamus or specific performance by court order, to cause the Authority or Obligation Fund Trustee, as the case may be, to comply with its obligation under this Disclosure Agreement. A default under this Disclosure Agreement shall not be deemed an Event of Default under the Revenue Obligation Resolution, and the sole remedy under this Disclosure Agreement in the event of any failure of the Authority or the Obligation Fund Trustee to comply with this Disclosure Agreement shall be an action to compel performance. The Authority acknowledges and agrees that each of the rights, protections and indemnifications provided to the Obligation Fund Trustee under the Revenue Obligation Resolution shall also be afforded to the Obligation Fund Trustee with respect to this Disclosure Agreement.

SECTION 12. Governing Law. The provisions of this Disclosure Agreement shall be governed by the laws of the State of South Carolina, without regard to conflict of law principles.

[Signature Page Follows]

IN WITNESS WHEREOF, the Authority and the Obligation Fund Trustee have caused this Disclosure Agreement to be executed and attested by their authorized officers or officials, as of the day and year first above written.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

By: ______________________________

Its: Treasurer

THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., as Obligation Fund Trustee

By: ______________________________

Its: Vice President

EXHIBIT A

NOTICE TO REPOSITORIES OF FAILURE TO FILE ANNUAL REPORT

Name of Issuer:	South Carolina Public Service Authority
Name of Bond Issue:	Revenue Obligations, 2026 Tax-Exempt Improvement Series A (the "2026A Bonds"), 2026 Taxable Improvement Series B (the "2026B Bonds") and 2026 Tax-Exempt Refunding Series C (the "2026C Bonds")
Date of Issuance:	March __, 2026

NOTICE IS HEREBY GIVEN that South Carolina Public Service Authority (the "Authority") has not provided an Annual Report with respect to the above-named 2026A Bonds, 2026B Bonds and 2026C Bonds as required by each of the Sixty-Fourth Series and Supplemental Resolution, Sixty-Fifth Series and Supplemental Resolution and Sixty-Sixth Series and Supplemental Resolution authorizing the 2026A Bonds, 2026B Bonds and 2026C Bonds, respectively. The Authority anticipates that the Annual Report will be filed by ____________________.

Dated: ____________________

____
Trustee on behalf of Authority

cc: The Authority

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