K. Chad Burgess
Managing Counsel
Dominion Energy Services, Inc.

220 Operation Way, MC OSC 1A, Cayce, SC 29033
DominionEnergy.com

March 26, 2024

VIA ELECTRONIC FILING

The Honorable Jocelyn Boyd
Chief Clerk/Executive Director
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29211

RE: Dominion Energy South Carolina, Inc. - Federal Energy Regulatory Commission (FERC Form No. 1 and FERC Form No. 2)

South Carolina Generating Company - Federal Energy Regulatory Commission (FERC Form No. 1)
Non-Docket No. 2021-5-EG

Dear Ms. Boyd:

In accordance with the S.C. Code Ann. Regs. 103-312 and 103-412 (2012), Dominion Energy South Carolina, Inc. ("DESC") hereby files with the Public Service Commission of South Carolina ("Commission") one (1) copy of DESC's Federal Energy Regulatory Commission ("FERC") Form No. 1 and FERC Form No. 2.

Additionally, and in accordance with S.C. Code Ann. Regs. 103-312 (2012), South Carolina Generating Company ("GENCO") hereby files with the Commission one (1) copy of GENCO's FERC Form No. 1.

If you have any questions or concerns, please do not hesitate to contact us.[1]

Very truly yours,

K. Chad Burgess

KCB/kms
cc: All Parties of Record
(via electronic mail and Notice of Filing)

[1] Unless indicated otherwise by the Notice of Electronic Filing to be issued by the Commission's E-Filing System in response to this filing, all Authorized E-Filers will be served electronically pursuant to S.C. Code Ann. Regs. 103-817.1.

THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company) Dominion Energy South Carolina, Inc.	Year/Period of Report End of: 2023/ Q4

Deloitte & Touche LLP
901 E. Byrd St
Suite 820
Richmond, VA 23219
USA
www.deloitte.com

INDEPENDENT AUDITOR'S REPORT

Dominion Energy South Carolina, Inc.
Cayce, South Carolina

Opinion

We have audited the financial statements of Dominion Energy South Carolina, Inc. (an indirect, wholly-owned subsidiary of Dominion Energy, Inc.) (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2023, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis for the year then ended, included on pages 110 through 123, excluding pages 122a and 122b, of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements (the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2023, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company, 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 opinion.

Emphasis of Matter — Basis of Accounting

As discussed before Note 1 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. As a result, the financial statements may not be suitable for another purpose. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Management is also responsible 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 the Company's ability to continue as a going concern for one year after the date that the financial statements are available to be issued.

Auditor’s 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 auditor’s report that includes our opinion. 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 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 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 the Company’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 the Company’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.

Restriction on Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

March 22, 2024

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

   The CPA Certification Statement should:

   a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

   b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

   "In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

   Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

IV. When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. **Where to Send Comments on Public Reporting Burden.**

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

to the extent the Commission may deem necessary or useful for the purposes of this Act.

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Dominion Energy South Carolina, Inc.	02 Year/ Period of Report End of: 2023/ Q4
03 Previous Name and Date of Change (If name changed during year) /	
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 220 Operation Way, Cayce, SC 29033-3701	
05 Name of Contact Person Lisa Honeycutt	06 Title of Contact Person Accounting Manager
07 Address of Contact Person (Street, City, State, Zip Code) 220 Operation Way - MC OSC 2B, Cayce, SC 29033-3701	

08 Telephone of Contact Person, Including Area Code (803) 217-7416	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/22/2024

Annual Corporate Officer Certification

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Mark F. Lindley	03 Signature Mark F. Lindley Mark Lindley	04 Date Signed (Mo, Da, Yr) 03/22/2024
02 Title Controller		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	

28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	
36	Accumulated Deferred Investment Tax Credits	266	
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272	
39	Accumulated Deferred Income Taxes-Other Property	274	
40	Accumulated Deferred Income Taxes-Other	276	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310	
46	Electric Operation and Maintenance Expenses	320	
47	Purchased Power	326	
48	Transmission of Electricity for Others	328	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant (Account 403, 404, 405)	336	
53	Regulatory Commission Expenses	350	
54	Research, Development and Demonstration Activities	352	
55	Distribution of Salaries and Wages	354	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401a	
62	Monthly Peaks and Output	401b	
63	Steam Electric Generating Plant Statistics	402	

64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	N/A
66.2	**Energy Storage Operations (Small Plants)**	419	N/A
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Mark F. Lindley

Controller

220 Operation Way, Cayce, SC 29033-3701

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: SC

Date of Incorporation: 1924-07-19

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

South Carolina - Electric, Gas

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). SCANA is a South Carolina Corporation created in 1984 as a holding company. SCANA holds directly all of the Capital Stock of the respondent. Effective January 1, 2019, SCANA became a wholly-owned subsidiary of Dominion Energy, Inc.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	South Carolina Fuel Company, Inc.	Acquires, owns, provides financing for and sells to DESC nuclear fuel, certain fossil fuels and emission allowances.	0%	[(a)] footnote
2	South Carolina Generating Company, Inc.	Owns A. M. Williams Generating Station and sells electricity solely to DESC.	0%	[(b)] footnote
3	SRFI, LLC	A single member LLC holding investments in companies involved with re-engineered fuel.	0%	[(c)] footnote
4	Canadys Refined Coal, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(d)] footnote
5	Brandon Shores Coaltech, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(e)] footnote
6	Louisa Refined Coal, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(f)] footnote

FOOTNOTE DATA

(a) Concept: FootnoteReferences

Control held by Dominion Energy South Carolina, Inc. (DESC) under the terms of a fuel contract. The accounts of South Carolina Fuel Company, Inc. are fully consolidated herein.

(b) Concept: FootnoteReferences

DESC has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, DESC consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

(c) Concept: FootnoteReferences

SRFI, LLC is a single member LLC in which DESC is the sole member and no stock was issued.

(d) Concept: FootnoteReferences

DESC holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc. In the first quarter of 2021, demolition and removal of partnership equipment which was located at DESC's Cope Station site occurred.

(e) Concept: FootnoteReferences

DESC holds a 10% interest in Brandon Shores Coaltech, LLC. The other member is AJG Coal, Inc.

(f) Concept: FootnoteReferences

DESC holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1			[d]0		
2	President	W. Keller Kissam	1,126,467		
3	President, Nuclear Operations and Chief Nuclear Officer	[a] Eric S. Carr	188,258	2023-07-01	
4	Chief Executive Officer	Diane Leopold	627,202		
5	Executive Vice President, Chief of Staff and Corporate Secretary	[b] Carter M. Reid	268,122		2023-12-31
6	Senior Vice President - Regulatory Affairs and Customer Experience	Corynne S. Arnett	270,562		
7	Senior Vice President, Chief Legal Officer and General Counsel	Carlos M. Brown	169,131		
8	Senior Vice President, Controller and Chief Accounting Officer	Michele L. Cardiff	151,154		
9	Senior Vice President - Corporate Affairs & Communications	William L. Murray	289,919		
10	Vice President and General Manager - North Carolina & South Carolina Gas Distribution	D. Russell Harris	304,917		
11	Senior Vice President and Chief Nuclear Officer	[c] Daniel G. Stoddard	318,107		2024-06-30
12	Senior Vice President and Chief Financial Officer	Steven D. Ridge	173,865		
13	Senior Vice President – Administrative Services	W. Keith Windle	93,134		
14	Vice President - Power Generation	Iris N. Griffin	605,045		
15	Vice President and Treasurer	Darius A. Johnson	90,171		
16	Vice President – Transmission & Delivery	M. Shaun Randall	542,779		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OfficerName

Eric S. Carr was elected President - Nuclear Operations, effective June 5, 2023, and then President - Nuclear Operations and Chief Nuclear Officer, effective July 1, 2023.

(b) Concept: OfficerName

Carter M. Reid, Executive Vice President, Chief of Staff and Corporate Secretary, retired effective January 1, 2024.

(c) Concept: OfficerName

Daniel G. Stoddard resigned as Senior Vice President and Chief Nuclear Officer effective June 30, 2023. Mr. Stoddard was elected Senior Vice President and President - Contracted Assets of Dominion Energy, Inc., and President of Dominion Generation, Inc., effective July 1, 2023. Mr. Stoddard retired from Dominion Energy, Inc. effective August 1, 2023.

(d) Concept: OfficerSalary

These officers are paid by Dominion Energy Services, Inc. and the amounts presented represent only Dominion Energy South Carolina's share of their salary expense.

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	R.M. Blue	Richmond, Virginia	false	false
2	W. K. Kissam (President)	Cayce, South Carolina	false	false
3	D. Leopold (Chief Executive Officer)	Richmond, Virginia	false	false

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Schedule 1, Schedule 7, Schedule 8, Attachment H	ER10-516, ER10-855, ER10-1268, ER20-1836, ER22-1344

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20230515-5343	05/15/2023	ER10-516, ER10-855, ER10-1268	Annual Update Informational Filing	Schedule 1, 7, 8, Attachment H

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant in Service	g	58
2	320-323	Electric Operation and Maintenance Expenses	b	96
3	356	Common Utility Plant and Expenses	N/A	N/A

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None

2. None

3. None

4. None

5. None

6. Short-term borrowings below have been authorized by FERC (Docket No. ES21-25-000 and Docket No. ES23-26-000).

The Company's obligations under non-affiliated short-term borrowing arrangements on the respective Balance Sheet dates were as follows:

12/31/2023 - $254,185,000
12/31/2022 - $249,133,000

In January 2023, DESC applied to FERC for a two-year renewal of its short-term borrowing authorization. On March 15, 2023, in Docket No. ES23-26-000, FERC granted DESC's request for a two-year renewal of its short-term borrowing authorization beginning on March 25, 2023. DESC may issue short-term debt in amounts not to exceed $2.2 billion outstanding.

South Carolina Fuel Company, Inc. (Fuel Company), an affiliate of DESC, is consolidated in this filing (see Note 1 to the Financial Statements), and participates in an intercompany credit agreement with Dominion Energy. At January 1, 2023, Fuel Company had borrowings outstanding under this credit agreement totaling $252,241,085. During 2023, Fuel Company borrowed $151,831,000, incurred interest charges of $13,480,895 and repaid $144,171,000 under this agreement. At December 31, 2023, Fuel Company had principal and interest outstanding under this agreement totaling $273,381,980. Principal and interest outstanding are reported in FERC Account 233 - Notes Payable to Associated Companies.

As part of its short debt authorization in Docket No. ES23-26-000, DESC has FERC authorization to participate in an Intercompany Credit Agreement with Dominion Energy under which DESC may have short-term borrowings outstanding up to $900 million. At January 1, 2023, DESC had borrowings outstanding under this credit agreement totaling $491,528,872. During 2023, DESC borrowed $1,624,623,000, incurred interest charges of $31,219,796, and repaid $2,011,890,000 under this agreement. At December 2023, DESC had principal and interesting outstanding under this agreement totaling $135,481,668. Principal and interest outstanding are recorded in FERC Account 233 - Notes Payable to Associated Companies.

DESC is obligated with respect to an aggregate of $35 million of Industrial Revenue Bonds which are secured by letters of credit. These letters of credit expire, subject to renewal, in the fourth quarter of 2024.

For additional information, see Notes 6, 8 and 9 to the Financial Statements.

7. None

8. None

9. See Notes 3 and 12 to the Financial Statements.

10. None

12. Important Changes

<u>Business Review</u>
In November 2022, Dominion Energy announced the commencement of a business review of value-maximizing strategic business actions, alternatives to its current business mix and capital allocation and regulatory options which may assist customers to manage costs and provide greater predictability to its long term, state-regulated utility value proposition. In September 2023, Dominion Energy entered agreements to sell East Ohio, PSNC, Questar Gas and Wexpro to Enbridge and completed the sale of its 50% noncontrolling limited partner interest in Cove Point to BHE under the agreement signed in July 2023. Dominion Energy is in the process of finalizing its long-term financial plan following the conclusion of the review. The implementation of recommendations resulting from the business review, including the items discussed above, is expected to have a material impact on Dominion Energy's future results of operations, financial condition and/or cash flows.

<u>Future Environmental Regulations</u>
Climate Change
The federal government and several states in which Dominion Energy operates have announced a commitment to achieving carbon reduction goals. In February 2021, the U.S. rejoined the Paris Agreement, which establishes a universal framework for addressing GHG emissions. States may also enact legislation relating to climate change matters such as the reduction of GHG emissions and renewable energy portfolio standards. To the extent legislation is enacted at the federal or state level that is more restrictive than Dominion Energy's commitment to achieving net zero emissions by 2050, compliance with such legislation could have a material impact to Dominion Energy's financial condition and/or cash flows.

State Actions Related to Air and GHG Emissions
In August 2017, the Ozone Transport Commission released a draft model rule for control of NOX emissions from natural gas pipeline compressor fuel-fire prime movers. States within the ozone transport region, including states in which Dominion Energy has natural gas operations, are expected to develop reasonably achievable control technology rules for existing sources based on the Ozone Transport Commission model rule. States outside of the Ozone Transport Commission may also consider the model rules in setting new reasonably achievable control technology standards. Several states in which Dominion Energy operates are developing or have announced plans to develop state-specific regulations to control GHG emissions, including methane. Dominion Energy cannot currently estimate the potential financial statement impacts related to these matters, but there could be a material impact to its financial condition and/or cash flows.

Inflation Reduction Act
The IRA includes provisions which impose an annual fee for waste methane emissions from the oil and natural gas industry beginning with emissions reported in calendar year 2024 to the extent that an entity's emissions exceed a stated threshold, with implementation to be addressed by future rulemaking by the EPA. Pending the completion of such rulemaking, Dominion Energy currently does not expect these provisions to materially affect its future results of operations, financial condition and/or cash flows.
Proposed EPA Rules
In March 2023, the EPA released a proposed rule to further revise the Effluent Limitations Guidelines for the Steam Electric Power Generating Category, which apply primarily to wastewater discharges at coal and oil steam generating stations. Also in March 2023, the EPA released its first proposed rule to establish national drinking water standards for PFAS. Dominion Energy anticipates that the EPA will release additional rulemakings as part of an overall strategy to identify and mitigate PFAS exposure. In April 2023, the EPA released a proposal to tighten aspects of the Mercury and Air Toxics Standards, including the reduction of emissions limits for 83 filterable particulate matter, and requiring the use of continuous emissions monitoring systems to demonstrate compliance. In May 2023, the EPA proposed a package of rules designed to reduce CO_2 emissions from certain fossil fuel-fired electric generating units. The proposal sets standards of performance and emission guidelines for CO_2 emissions from new gas-fired combustion turbines and modified coal-fired steam generating units. The proposed rulemaking package also proposes emission guidelines, including presumptive emission limits, for existing coal, oil and gas-fired steam generating units and certain gas-fired combustion turbines. Also in May 2023, the EPA released a proposed rule to regulate inactive surface impoundments located at retired generating stations that contained CCR and liquids after October 2015, and certain other inactive or previously closed surface impoundments, landfills or other areas that contain accumulations of CCR. Until the EPA ultimately takes final action on these rulemakings, Dominion Energy is unable to predict whether or to what extent the new rules will ultimately require additional controls. The expenditures required to implement additional controls could have a material impact on the Company's financial condition and cash flows.

PHMSA Regulation
The most recent reauthorization of PHMSA included new provisions on historical records research, maximum-allowed operating pressure validation, use of automated or remote-controlled valves on new or replaced lines, increased civil penalties and evaluation of expanding integrity management beyond high consequence areas. PHMSA has not yet issued new rulemaking on most of these items.

Dodd-Frank Act
The CEA, as amended by Title VII of the Dodd-Frank Act, requires certain over-the counter derivatives, or swaps, to be cleared through a derivatives clearing organization and, if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. Non-financial entities that use swaps to hedge or mitigate commercial risk may elect the end-user exception to the CEA's clearing requirements. The Company utilizes the end-user exception with respect to its swaps. If, as a result of changes to the rulemaking process, the Company can no longer utilize the end-user exception or otherwise becomes subject to mandatory clearing, exchange trading or margin requirements, it could be subject to higher costs due to decreased market liquidity or increased margin payments. In addition, Dominion Energy's swap dealer counterparties may attempt to pass-through additional trading costs in connection with changes to the rulemaking process. Due to the evolving rulemaking process, the Company is currently unable to assess the potential impact of the Dodd-Frank Act's derivative-related provisions on its financial condition, results of operations or cash flows.

<u>Federal Income Tax Laws</u>
Inflation Reduction Act
The IRA imposes a 15% alternative minimum tax on GAAP net income, as adjusted for certain items, of corporations in excess of $1 billion, for tax years beginning after December 31, 2022. Entities that are subject to the alternative minimum tax may use tax credits to reduce the liability by up to 75% and will receive a tax credit carryforward with an indefinite life that can be claimed against the regular tax in future years. Pending final guidance, the alternative minimum tax is not expected to have an effect on the assessment of the realizability of the Company's deferred tax assets or a material impact on the Company's future results of operations or cash flows.

Tax Repairs Guidance
In April 2023, the IRS issued safe harbor guidance to taxpayers on the treatment of amounts paid to repair, maintain, replace, or improve natural gas distribution property, including whether expenditures should be deducted as repairs or capitalized and depreciated on tax returns. The guidance includes safe harbor tax accounting methods which a taxpayer may choose to elect and provides special transition rules and incentives that vary depending on which tax year is the year of change. Dominion Energy is evaluating this new guidance and while it cannot currently estimate the potential financial statement impacts, it does not expect a material impact to its results of operations, financial condition and/or cash flows based on its expectation that the East Ohio, PSNC and Questar Gas Transactions will close in 2024.

13. The following changes in Company Officers and Directors became effective during 2023:

M. Brandon Phibbs was elected Vice President - Financial Management effective January 1, 2023.

George A. Lippard, III, Site Vice President - V.C. Summer Power Station retired from the Company effective January 31, 2023.

Robert Justice was elected Site Vice President - V.C. Summer Power Station effective February 1, 2023.

Douglas C. Lawrence, Vice President - Nuclear Operations & Fleet Performance, was promoted to Senior Vice President - Nuclear Operations & Fleet Performance, effective May 1, 2023.

Eric S. Carr was elected President - Nuclear Operations, effective June 5, 2023, and then President - Nuclear Operations and Chief Nuclear Officer, effective July 1, 2023.

Joseph A. Woomer resigned as Vice President – New Business & Customer Solutions, effective May 31, 2023. Mr. Woomer was elected Senior Vice President - Electric Transmission of Virginia Electric and Power Company, effective June 1, 2023.

Daniel G. Stoddard resigned as Senior Vice President and Chief Nuclear Officer effective June 30, 2023. Mr. Stoddard was elected Senior Vice President and President - Contracted Assets of Dominion Energy, Inc., and President of Dominion Generation, Inc., effective July 1, 2023. Mr. Stoddard retired from Dominion Energy, Inc. effective August 1, 2023.

Jason E. Williams resigned as Vice President - Environmental & Sustainability effective July 31, 2023. Mr. Williams was elected Vice President - Corporate Communications for Dominion Energy Services, Inc., effective August 1, 2023.

Mary A. "Molly" Parker was elected Vice President - Environmental & Sustainability effective August 1, 2023.

Lauren V. Adkins resigned as Assistant Treasurer effective September 28, 2023.

Richard M. Davis, Jr. was appointed Assistant Treasurer effective October 3, 2023.

The following changes in Company Officers and Directors have become or will become effective in 2024:

Carter M. Reid, Executive Vice President, Chief of Staff and Corporate Secretary, retired effective January 1, 2024.

Carlos M. Brown, Senior Vice President, Chief Legal Officer and General Counsel, was elected Executive Vice President, Chief Legal Officer, and Corporate Secretary, effective January 1, 2024.

Jim O. Stuckey II, Vice President-Legal (Litigation, Labor & Employment, and Utility Operations), was elected Vice President and General Counsel effective January 1, 2024.

Steven D. Ridge, Senior Vice President, and Chief Financial Officer, was elected Executive Vice President and Chief Financial Officer, effective January 1, 2024.

Corynne S. Arnett, Senior Vice President-Regulatory Affairs and Customer Experience, was elected Executive Vice President-Regulatory Affairs and Customer Experience, effective January 1, 2024.

Caitlin H. Porada, Vice President-Financial Management (DES and Contracted Assets), was elected Vice President-Corporate Planning and Financial Analysis effective February 1, 2024.

Elizabeth L. Chester, Vice President-Regulatory Affairs, was elected Vice President-Segment Planning (Regulated) effective February 1, 2024.

J. Scott Gaskill, General Manager-Regulatory Affairs, was elected Vice President-Regulatory Affairs, effective February. 1, 2024.

David M. McFarland, Vice President-Investor Relations, was elected Vice President-Investor Relations and Treasurer effective February 1, 2024,

Darius A. Johnson, Vice President, and Treasurer, resigned from Dominion Energy South Carolina effective February 1, 2024 and was elected Vice President-Human Resources of Dominion Energy effective February 1, 2024,
L. Wayne Duman, Vice President-Financial Planning & Analysis, will become Vice President & Special Advisor to the Chief Financial Officer on February 1, 2024 and will retire effective May 1, 2024.

14. Not Applicable

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	14,703,446,077	13,941,089,802
3	Construction Work in Progress (107)	200	569,573,518	514,217,273
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		15,273,019,595	14,455,307,075
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,869,410,815	5,620,270,875
6	Net Utility Plant (Enter Total of line 4 less 5)		9,403,608,780	8,835,036,200
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	311,434	48,564,107
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		173,580,747	120,440,247
9	Nuclear Fuel Assemblies in Reactor (120.3)		143,435,288	165,107,401
10	Spent Nuclear Fuel (120.4)		291,470,459	216,049,432
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	379,746,492	346,659,275
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		229,051,436	203,501,912
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,632,660,216	9,038,538,112
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		23,924,323	27,241,741
19	(Less) Accum. Prov. for Depr. and Amort. (122)		122,620	448,551
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	35,236	5,573
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		60,309	60,309
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		246,106,355	199,842,132
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		167,417,363	211,620,705
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		437,420,966	438,321,909

33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		1,230,015	[a]10,983,073
36	Special Deposits (132-134)		10,559,952	10,000
37	Working Fund (135)		100	100
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		249,790,910	227,284,438
41	Other Accounts Receivable (143)		98,342,174	150,661,332
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,581,381	5,817,741
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		56,323,614	17,050,376
45	Fuel Stock (151)	227	63,938,400	63,773,029
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	215,964,367	202,883,477
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	622,120	622,919
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		20,651,026	29,223,948
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		9,287,901	9,229,700
57	Prepayments (165)		82,974,960	75,587,949
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		176,096,729	188,423,470
62	Miscellaneous Current and Accrued Assets (174)		4,417,947	9,380,768
63	Derivative Instrument Assets (175)		176,250,421	252,398,982
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		167,417,363	211,620,705
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		991,451,892	1,020,075,115
68	**DEFERRED DEBITS**			

69	Unamortized Debt Expenses (181)		26,320,017	22,574,777
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,172,114,668	2,296,366,163
72	Other Regulatory Assets (182.3)	232	1,410,169,893	1,796,056,207
73	Prelim. Survey and Investigation Charges (Electric) (183)		345,726	2,781,382
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	77,951,336	74,260,878
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		8,312,399	9,406,573
82	Accumulated Deferred Income Taxes (190)	234	865,503,230	1,066,462,573
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		4,560,717,269	5,267,908,553
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,622,250,343	15,764,843,689

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: Cash

During 2022, $2,214,931 of Federal Customer Assistance Funds was applied against customer accounts. The remaining cash was returned to the Federal government.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250	100,000	100,000
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	3,516,300,056	3,516,300,056
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118	[a]592,183,810	[a]417,628,866
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,140,429)	(1,517,180)
16	Total Proprietary Capital (lines 2 through 15)		4,679,513,180	4,504,581,485
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	4,222,814,000	3,722,814,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	1,075,636	1,110,003
22	Unamortized Premium on Long-Term Debt (225)		6,832,429	7,219,974
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		18,549,713	16,300,029
24	Total Long-Term Debt (lines 18 through 23)		4,212,172,352	3,714,843,948
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		20,259,378	23,525,583
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		4,235,039	4,105,031
29	Accumulated Provision for Pensions and Benefits (228.3)		115,409,244	116,192,785
30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			

32	Long-Term Portion of Derivative Instrument Liabilities		229,876	
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		712,673,283	611,702,299
35	Total Other Noncurrent Liabilities (lines 26 through 34)		852,806,820	755,525,698
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		254,185,000	249,133,000
38	Accounts Payable (232)		249,122,114	325,300,517
39	Notes Payable to Associated Companies (233)		(b) 408,863,648	(d) 743,769,957
40	Accounts Payable to Associated Companies (234)		126,461,845	134,661,571
41	Customer Deposits (235)		75,388,955	71,956,986
42	Taxes Accrued (236)	262	293,344,738	272,392,558
43	Interest Accrued (237)		79,117,641	75,195,689
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		17,331,000	26,421,832
48	Miscellaneous Current and Accrued Liabilities (242)		57,380,333	128,175,861
49	Obligations Under Capital Leases-Current (243)		5,410,659	7,261,791
50	Derivative Instrument Liabilities (244)		229,876	
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		229,876	
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,566,605,933	2,034,269,762
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	12,903,109	14,189,650
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	56,595,996	60,699,463
60	Other Regulatory Liabilities (254)	278	2,188,694,833	2,510,661,611
61	Unamortized Gain on Reacquired Debt (257)			0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	10,037,513	10,282,215
63	Accum. Deferred Income Taxes-Other Property (282)		1,285,957,986	1,250,537,444
64	Accum. Deferred Income Taxes-Other (283)		756,962,621	909,252,413
65	Total Deferred Credits (lines 56 through 64)		4,311,152,058	4,755,622,796
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,622,250,343	15,764,843,689

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2023, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(b) Concept: NotesPayableToAssociatedCompanies

Includes borrowings outstanding, plus accrued interest, under the intercompany credit agreement with Dominion Energy as follows:

DESC	$	135,481,668
SCFC		273,381,980
Total	$	408,863,648

(c) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2022, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(d) Concept: NotesPayableToAssociatedCompanies

Includes borrowings outstanding, plus accrued interest, under the intercompany credit agreement with Dominion Energy as follows:

DESC	$	491,528,872
SCFC		252,241,085
Total	$	743,769,957

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	3,024,507,061	3,782,429,647			2,526,283,027	3,104,551,216	498,224,034	677,878,431		
3	Operating Expenses											
4	Operation Expenses (401)	320	1,377,504,574	2,052,571,436			1,060,733,662 [(f)]	1,549,791,852 [(g)]	316,770,912 [(h)]	502,779,584 [(i)]		
5	Maintenance Expenses (402)	320	180,137,234	179,516,003			167,992,088	169,767,135	12,145,146	9,748,868		
6	Depreciation Expense (403)	336	329,860,324	312,877,413			287,301,243	273,113,814	42,559,081	39,763,599		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	10,976,408	7,864,384			9,472,819	6,481,363	1,503,589	1,383,021		
9	Amort. of Utility Plant Acq. Adj. (406)	336	860,418	860,418			854,201	854,201	6,217	6,217		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		156,591,718	155,255,118			156,111,229	154,848,340	480,489	406,778		
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		16,672,971	16,302,258			16,672,971	16,302,258				
13	(Less) Regulatory Credits (407.4)		810,901	973,401			810,901	973,401				
14	Taxes Other Than Income Taxes (408.1)	262	284,729,693	268,866,976			252,368,086	238,294,418	32,361,607	30,572,558		
15	Income Taxes - Federal (409.1)	262	117,508,571	(33,204,682)			102,001,576	(44,048,195)	15,506,995	10,843,513		
16	Income Taxes - Other (409.1)	262	(65,272,734)	5,422,103			(68,426,927)	3,437,365	3,154,193	1,984,738		
17	Provision for Deferred Income Taxes (410.1)	234, 272	441,106,865	432,521,681			418,687,162	402,039,153	22,419,703	30,482,528		

18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	409,222,696	288,959,282			383,197,802	260,510,312	26,024,894	28,448,970		
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,286,541)	(1,296,972)			(1,242,585)	(1,252,722)	(43,956)	(44,250)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,439,355,904	3,107,623,453			2,018,516,822	2,508,145,269	420,839,082	599,478,184		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		585,151,157	674,806,194			507,766,205	596,405,947	77,384,952	78,400,247		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,369,862	1,031,101								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		920,125	502,391								
33	Revenues From Nonutility Operations (417)		13,914,739	13,784,126								
34	(Less) Expenses of Nonutility Operations (417.1)		10,365,217	12,091,213								
35	Nonoperating Rental Income (418)		123,600	109,100								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	[(a)]205,370	937								
37	Interest and Dividend Income (419)		6,071,995	6,378,185								
38	Allowance for Other Funds Used During Construction (419.1)		(170,755)	(33,704)								
39	Miscellaneous Nonoperating Income (421)		3,449,128	1,130,659								
40	Gain on Disposition of Property (421.1)		[(b)]31,075,712	[(d)]44,513,748								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		44,754,309	54,320,548								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		[(c)]3,049,050	[(e)]4,020,163								
44	Miscellaneous Amortization (425)		33,834	33,834								
45	Donations (426.1)		4,724,180	4,880,992								
46	Life Insurance (426.2)		19,169	9,534								
47	Penalties (426.3)		24,369	821								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		4,121,192	2,640,590								
49	Other Deductions (426.5)		5,439,522	13,724,670								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		17,411,316	25,310,604								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	831,255	464,647								

53	Income Taxes-Federal (409.2)	262	(33,167,161)	(36,351,727)								
54	Income Taxes-Other (409.2)	262	303,880	(5,353,388)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	42,633,110	68,077,291								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	12,918,779	15,349,118								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(2,317,695)	11,487,705								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		29,660,688	17,522,239								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		198,577,798	190,967,172								
63	Amort. of Debt Disc. and Expense (428)		1,545,075	1,444,929								
64	Amortization of Loss on Reaquired Debt (428.1)		1,094,173	1,094,173								
65	(Less) Amort. of Premium on Debt-Credit (429)		387,545	370,065								
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)											
67	Interest on Debt to Assoc. Companies (430)		44,700,692	12,052,249								
68	Other Interest Expense (431)		14,286,782	11,111,739								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		19,560,074	6,558,810								
70	Net Interest Charges (Total of lines 62 thru 69)		240,256,901	209,741,387								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		374,554,944	482,587,046								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		374,554,944	482,587,046								

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: EquityInEarningsOfSubsidiaryCompanies

Per the USoA instructions, the Company is using Account 418.1 – Equity in Earnings of Subsidiary Companies to account for its equity method losses or gains related to corporate joint ventures carried in Account 123.1 – Investment in Subsidiary Companies. Since these equity method losses or gains are funded by the Company, there are no undistributed retained earnings related to these investments.

(b) Concept: GainOnDispositionOfProperty

Includes $20.1 million related to gain on sale of certain utility property. $10.6 million related to gain on sale of certain property.

(c) Concept: LossOnDispositionOfProperty

Includes $3 million write off to certain utility property.

(d) Concept: GainOnDispositionOfProperty

Includes $19.5 million related to gain on sale of certain utility property and $21.5 million related to gain on sale of certain nonutility property.

(e) Concept: LossOnDispositionOfProperty

Includes $3.9 million write off to certain utility property.

(f) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $959,889 billed from Dominion Energy Services, Inc.

(g) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $1,098,680 billed from Dominion Energy Services, Inc.

(h) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $121,918 billed from Dominion Energy Services, Inc.

(i) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $155,759 billed from Dominion Energy Services, Inc.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		302,466,343	219,879,297
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Reclassification from Account 219 - Accumulated			
10.2	Other Comprehensive Income			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		374,349,574	482,586,109
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Federal Power Act Appropriation	215.1	[a](82,216)	
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(82,216)	
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1		238	(200,000,000)	(400,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(200,000,000)	(400,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		205,370	937
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		476,939,071	302,466,343
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			

	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		115,244,739	115,162,523
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		115,244,739	115,162,523
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		(b)592,183,810	(e)417,628,866
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		(c)205,370	937
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Funded Equity Method Losses		(d)205,370	937
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AppropriationsOfRetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2023, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(b) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2023, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(c) Concept: EquityInEarningsOfSubsidiaryCompanies

Per the USoA instructions, the Company is using Account 418.1 – Equity in Earnings of Subsidiary Companies to account for its equity method losses or gains related to corporate joint ventures carried in Account 123.1 – Investment in Subsidiary Companies. Since these equity method losses or gains are funded by the Company, there are no undistributed retained earnings related to these investments.

(d) Concept: ChangesUnappropriatedUndistributedSubsidiaryEarningsCredits

Per the USoA instructions, the Company is using Account 418.1 – Equity in Earnings of Subsidiary Companies to account for its equity method losses or gains related to corporate joint ventures carried in Account 123.1 – Investment in Subsidiary Companies. Since these equity method losses or gains are funded by the Company, there are no undistributed retained earnings related to these investments.

(e) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2022, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	374,554,944	482,587,046
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	329,885,852	312,961,028
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Utility Plant and Acquisition Adjustment	11,870,660	8,758,636
5.2	Amortization - DER, Muni Franchise, Unrecovered Plt. & OCI	172,830,539	169,649,397
5.3	Amortization of Nuclear Fuel	33,087,217	38,568,240
8	Deferred Income Taxes (Net)	83,845,391	246,829,858
9	Investment Tax Credit Adjustment (Net)	(1,286,541)	(1,296,972)
10	Net (Increase) Decrease in Receivables	28,966,564	(61,782,127)
11	Net (Increase) Decrease in Inventory	(4,731,540)	(67,290,847)
12	Net (Increase) Decrease in Allowances Inventory	799	1,484
13	Net Increase (Decrease) in Payables and Accrued Expenses	(84,179,747)	113,859,756
14	Net (Increase) Decrease in Other Regulatory Assets	352,656,991	(413,933,166)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(247,138,528)	(326,741,616)
16	(Less) Allowance for Other Funds Used During Construction	(170,755)	(33,704)
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1		[(a)]15,421,913	[(f)]40,331,321
18.2	Discount / Premium on Long-Term Debt	192,771	167,069
18.3	Carrying Cost Recovery	(5,955,055)	(5,775,581)
18.4	(Gain) / Loss on Disposition of Assets	(29,122,399)	(38,860,898)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	1,031,070,586	498,066,332
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	[(b)](875,723,574)	[(g)](648,226,217)

27	Gross Additions to Nuclear Fuel	(59,758,917)	(26,372,618)
28	Gross Additions to Common Utility Plant	[(c)](12,226,341)	[(h)](18,775,963)
29	Gross Additions to Nonutility Plant	[(d)](455,476)	[(i)]509,884
30	(Less) Allowance for Other Funds Used During Construction	170,755	33,704
31	Other (provide details in footnote):		
31.1	Salvage Received	4,521,772	4,288,856
31.2	Cost of Removal	(21,471,539)	(55,490,928)
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(965,284,830)	(744,100,690)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(235,033)	8,489
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Proceeds-Sale of Fixed Assets & Investments	9,301,378	43,015,614
53.2	Other Investments	[(e)]984,631	[(j)](1,874,906)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(955,233,854)	(702,951,493)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	500,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	5,052,000	249,133,000
67	Other (provide details in footnote):		
67.1	Borrowings from Intercompany Credit Agreement	1,776,454,000	3,100,252,873
67.2	Deferred Financing Costs / Long-Term Debt Issuance Costs	(7,397,239)	(191,713)

70	Cash Provided by Outside Sources (Total 61 thru 69)	2,274,108,761	3,349,194,160
72	Payments for Retirement of:		
73	Long-term Debt (b)	(3,637,551)	(4,355,905)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Borrowings from Intercompany Credit Agreement	(2,156,061,000)	(2,783,098,872)
76.2	Premiums & Costs Related to Redemptions		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(200,000,000)	(400,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	(85,589,790)	161,739,383
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(9,753,058)	(43,145,778)
88	Cash and Cash Equivalents at Beginning of Period	10,983,173	54,128,951
90	Cash and Cash Equivalents at End of Period	1,230,115	10,983,173

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Includes $32,167,353 for changes in the Company's net postretirement benefit obligation, ($17,936,963) for Prepayments, $3,431,969 for Customer Deposits and various other Balance Sheet changes not presented as separate line items.

(b) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

For the twelve months ended December 31, 2023, the Company added $1,666,336 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($5,910,724) for capital leases in accordance with USoA General instructions No. 20.

(c) Concept: GrossAdditionsToCommonUtilityPlantInvestingActivities

For the twelve months ended December 31, 2023, the Company added $148,228 to its Common Utility Plant Property Account (118) and reduced the same account by ($730,231) for capital leases in accordance with USoA General Instruction No. 20.

(d) Concept: GrossAdditionsToNonutilityPlantInvestingActivities

For the twelve months ended December 31, 2023, the Company added $33,663 to its Nonutility Plant Property Account (121) and reduced the same account by ($324,609) for capital leases in accordance with USoA General Instruction No. 20.

(e) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Nuclear Decommissioning Trust

(f) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Includes ($50,375,910) for changes in the Company's net postretirement benefit obligation, $907,302 for Prepayments, $960,320 for Customer Deposits, ($30,609,908) liability reduction for property transfers for litigation settlements, $119,355,266 related to Year End Pension and OPEB Valuation and cash surrender value of Nuclear Decommissioning Trust Life Insurance and various other Balance Sheet changes not presented as separate line items

(g) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

For the twelve months ended December 31, 2022, the Company added $6,429,808 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($5,753,482) for capital leases in accordance with USoA General instructions No. 20.

(h) Concept: GrossAdditionsToCommonUtilityPlantInvestingActivities

For the twelve months ended December 31, 2022, the Company added $64,080 to its Common Utility Plant Property Account (118) and reduced the same account by ($2,318,732) for capital leases in accordance with USoA General Instruction No. 20.

(i) Concept: GrossAdditionsToNonutilityPlantInvestingActivities

For the twelve months ended December 31, 2022, the Company added $0 to its Nonutility Plant Property Account (121) and reduced the same account by ($393,265) for capital leases in accordance with USoA General Instruction No. 20.

(j) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Nuclear Decommissioning Trust

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

Glossary of Terms

The following abbreviations or acronyms used in this Form No. 1 are defined below:

Abbreviation or Acronym	**Definition**
2017 Tax Reform Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
ACE Rule	Affordable Clean Energy Rule
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income (loss)
ARO	Asset retirement obligation
BACT	Best available control technology
bcf	Billion cubic feet
BHE	The legal entity, Berkshire Hathaway Energy Company, one or more of its consolidated subsidiaries (including Eastern Energy Gas Holdings, LLC, Northeast Midstream Partners, LP and Cove Point effective November 2020), or the entirety of Berkshire Hathaway Energy Company and its consolidated subsidiaries
CAA	Clean Air Act
CCR	Coal combustion residual
CEA	Commodity Exchange Act
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as Superfund
CFO	Chief Financial Officer
CODM	Chief Operating Decision Maker
COO	Chief Operating Officer
CO2	Carbon dioxide
CUA	Capacity Use Area
CWA	Clean Water Act
DES	Dominion Energy Services, Inc.
DESC	The legal entity, Dominion Energy South Carolina, Inc., one or more of its consolidated entities or operating segment, or the entirety of Dominion Energy South Carolina, Inc. and its consolidated entities
DESS	Dominion Energy Southeast Services, Inc.
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	U.S. Department of Energy
Dominion Energy	The legal entity, Dominion Energy, Inc., one or more of its consolidated subsidiaries (other than DESC) or operating segments, or the entirety of Dominion Energy, Inc. and its consolidated subsidiaries
Dominion Energy South Carolina	Dominion Energy South Carolina operating segment
DSM	Demand-side management
ELG Rule	Effluent limitations guidelines for the steam electric power generating category
EMANI	European Mutual Association for Nuclear Insurance
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERISA	Employment Retirement Income Security Act of 1974
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FILOT	Fee in lieu of taxes
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	U.S. generally accepted accounting principles
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse gas
IRA	An Act to Provide for Reconciliation Pursuant to Title II of Senate Concurrent Resolution 14 of the 117th Congress (also known as the Inflation Reduction Act of 2022) enacted on August 16, 2022
IRS	Internal Revenue Service
LNG	Liquefied natural gas
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGD	Million gallons per day
MW	Megawatt
MWh	Megawatt hour
NAV	Net asset value
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NFEETS	Non-firm energy exchange transmission services
NND Project	V.C. Summer Units 2 and 3 nuclear development project under which DESC and Santee Cooper undertook to construct two Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina
NOx	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
Order 1000	Order issued by FERC adopting requirements for electric transmission planning, cost allocation and development
ORS	South Carolina Office of Regulatory Staff
PFAS	Per- and polyfluorinated substances, a group of widely used chemicals that break down very slowly over time in the environment
PGA	Purchased gas adjustment
PHMSA	U.S. Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Amendments Act of 1988
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company, a wholly-owned subsidiary of Dominion Energy
RICO	Racketeer Influenced and Corrupt Organizations Act
ROE	Return on equity
Santee Cooper	South Carolina Public Service Authority
SCANA	The legal entity, SCANA Corporation, one or more of its consolidated subsidiaries (other than DESC) or the entirety of SCANA Corporation and its consolidated subsidiaries
SCANA Combination	Dominion Energy's acquisition of SCANA completed on January 1, 2019 pursuant to the terms of the SCANA Merger Agreement
SCANA Merger Agreement	Agreement and plan of merger entered on January 2, 2018 between Dominion Energy and SCANA
SCANA Merger Approval Order	Final order issued by the South Carolina Commission on December 21, 2018 setting forth its approval of the SCANA Combination
SCDHEC	South Carolina Department of Health and Environmental Control
SCDOR	South Carolina Department of Revenue
Scope 1 emissions	Emissions that are produced directly by an entity's own operations
Scope 2 emissions	Emissions from electricity a company consumes but does not generate from its own facilities
Scope 3 emissions	Emissions generated downstream of company operations by customers and upstream by suppliers
SEC	U.S. Securities and Exchange Commission
SEEM	Southeast Energy Exchange Market
SO2	Sulfur dioxide
South Carolina Commission	Public Service Commission of South Carolina

South Carolina Commission	Public Service Commission of South Carolina
Summer	V.C. Summer nuclear power station
Toshiba	Toshiba Corporation, parent company of Westinghouse
Toshiba Settlement	Settlement Agreement dated as of July 27, 2017, by and among Toshiba, DESC and Santee Cooper
VIE	Variable interest entity
Virginia Power	The legal entity, Virginia Electric and Power Company, a wholly-owned subsidiary of Dominion Energy, one or more of its consolidated subsidiaries or operating segment, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries
Westinghouse	Westinghouse Electric Company LLC
WNA	Weather normalization adjustment

The financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. The significant differences from the Company's GAAP requirements are related to the classification of certain assets and liabilities to include (i) the classification of restricted cash amounts within other current assets in the GAAP financial statements, whereas these amounts are included within cash in the FERC financial statements; (ii) the classification of a portion of regulatory assets and liabilities as current assets and liabilities in the GAAP financial statements, whereas these amounts are reported as deferred debits and credits in the FERC financial statements; (iii) the current portion of long term debt is not classified as a current liability in the FERC financial statements; (iv) certain affiliated payables and receivables are presented on a gross basis in the FERC financial statements, whereas these are reported on a net basis in the GAAP financial statements; (v) accumulated deferred income taxes are reported on a gross basis in the FERC financial statements, whereas these amounts are reported on a net basis by jurisdiction in the GAAP financial statements; (vi) the removal of unrecognized tax benefits in deferred taxes for FERC reporting; (vii) accrued cost of removal is reported within accumulated provisions for depreciation in the FERC financial statements, whereas these amounts are reported within regulatory liabilities in the GAAP financial statements; (viii) debt issuance costs are reported within unamortized debt expense in the FERC financial statements, whereas these amounts are reported as a reduction to the carrying value of the debt in the GAAP financial statements; (ix) unamortized losses and gains on reacquired debt are reported within regulatory assets and liabilities in the GAAP basis financial statements and are separately presented within deferred debits and credits in the FERC financial statements; (x) the presentation of leases and the removal of regulatory assets recorded for GAAP reporting purposes related to leases; (xi) certain cloud computing arrangement costs are classified within net utility plant in the FERC financial statements whereas these amounts are included within prepayments on the GAAP basis statements; (xii) the non-service cost component of certain pension and other post employment benefits are reported within net utility plant and operation and maintenance expenses in the FERC financial statements, whereas these amounts are reported as regulatory assets and nonoperating expenses in the GAAP financial statements; and (xiii) the carrying value related to the planned retirement of certain peaking units is reported within net utility plant in the FERC financial statements until retirement, whereas these amounts are reported as regulatory assets in the GAAP financial statements. Also, certain charges associated with the abandonment of the NND Project are classified within operating income and taxes for GAAP reporting purposes, whereas these amounts are classified within nonoperating income (other deductions) for FERC reporting purposes. In addition, the accounts of GENCO are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

The Company adopted revised GAAP accounting guidance for the recognition, measurement, presentation, and disclosure of leasing arrangements in 2019. For FERC reporting purposes, as a result of the adoption of this guidance, the Company established leased assets and liabilities for operating leases in the existing FERC balance sheet accounts for leases, in addition to the assets and liabilities the Company already maintained for its capital lease amounts which are now considered finance leases. The Company follows the accounting guidance set forth in General Instruction 20 of the Uniform System of Accounts. The operating lease assets established upon the adoption of this new accounting guidance have been excluded from rate base in the Company's FERC jurisdictional cost of service rates.
These notes are based on the notes contained in DESC's Annual Report on Form 10-K filed with the SEC and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122.

Management has evaluated the impact of events occurring after December 31, 2023 up to February 23, 2024, the date that DESC's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 22, 2024. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Dominion Energy South Carolina, Inc.
Notes to Consolidated Financial Statements

1. NATURE OF OPERATIONS

DESC is a wholly-owned subsidiary of SCANA, which is a wholly-owned subsidiary of Dominion Energy.

DESC is engaged in the generation, transmission and distribution of electricity in the central, southern and southwestern portions of South Carolina. Additionally, DESC distributes natural gas to residential, commercial and industrial customers in South Carolina.

DESC manages its daily operations through one primary operating segment: Dominion Energy South Carolina. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

DESC makes certain estimates and assumptions in preparing its Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenues, expenses and cash flows for the periods presented. Actual results may differ from those estimates.

DESC's Consolidated Financial Statements include, after eliminating intercompany balances and transactions, the accounts of DESC and Fuel Company. DESC has concluded that Fuel Company is a VIE due to the members lacking the characteristics of a controlling financial interest. DESC is the primary beneficiary of Fuel Company and therefore is required to consolidate the VIE. The equity interest in Fuel Company is held solely by SCANA, DESC's parent. As a result, Fuel Company's equity and results of operations are reflected as noncontrolling interest in the Consolidated Financial Statements.

Fuel Company acquires, owns and provides financing for DESC's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 6.

Additionally, DESC purchases shared services from DES, an affiliated VIE that provides accounting, legal, finance and certain administrative and technical services to all Dominion Energy subsidiaries, including DESC. DESC has determined that it is not the primary beneficiary of DES as it does not have either the power to direct the activities that most significantly impact its economic performance or an obligation to absorb losses and benefits which could be significant to it. See Note 16 for amounts attributable to affiliates.

DESC reports certain contracts and instruments at fair value. See Note 9 for further information on fair value measurements.

DESC maintains pension and other postretirement benefit plans. See Note 11 for further information on these plans.

Certain amounts in the 2022 and 2021 Consolidated Financial Statements and Notes have been reclassified to conform to the 2023 presentation for comparative purposes; however, such reclassifications did not affect DESC's net income, total assets, liabilities, equity or cash flows.

Utility Plant

Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFUDC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFUDC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFUDC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. DESC calculated AFUDC using average composite rates of 5.2%, 2.5% and 2.5% for 2023, 2022 and 2021, respectively. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. DESC capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from utility plant-in-service when it becomes probable it will be abandoned and recorded as a regulatory asset for amounts expected to be collected through future rates.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property, and in most cases, include provisions for future cost of removal. The composite weighted average depreciation rates for utility plant by function were as follows:

	2023(1)	2022
Generation	**2.28 %**	2.29 %
Transmission	**2.54 %**	2.53 %
Distribution	**2.57 %**	2.50 %
Storage	**2.83 %**	2.80 %
General and other	**3.16 %**	3.05 %

(1) In 2021, a change in depreciation rates was approved in connection with the settlement of the electric base rate case, which resulted in a decrease to depreciation expense of $6 million for the year ended December 31, 2021, and $12 million for the years ended December 31, 2023 and 2022.

DESC records nuclear fuel amortization using the units-of-production method, which is included in fuel used in electric generation and recovered through the fuel cost component of retail electric rates.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine generator equipment, nuclear refueling outages and cyclical tree trimming and vegetation management are collected in rates and accrued in periods other than when incurred in accordance with approval by the South Carolina Commission for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Effective September 2021, DESC is authorized to collect $25 million annually through electric rates to offset certain turbine generator maintenance expenditures. Prior to September 2021, DESC was authorized to collect $18 million annually. For each of the years ended December 31, 2023, 2022 and 2021, DESC incurred $20 million for turbine generator maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the South Carolina Commission, DESC accrues $17 million annually for its portion of the nuclear refueling outages, that are scheduled to occur from the fall of 2021 through the fall of 2027 as well as unrecovered balances from the previous accrual cycle. Refueling outage costs incurred for which DESC was responsible totaled $26 million in 2023, $1 million in 2022 and $24 million in 2021.

Effective September 2021, DESC implemented a tree trimming and vegetation management accrual where costs associated with cyclical tree trimming and vegetation management are accrued over the five-year operating cycle DESC seeks to maintain for such activities. As approved by the South Carolina Commission, DESC accrues $28 million annually. In 2021, DESC accrued $9 million during the period the accrual was effective. During the years ended December 31, 2023, 2022 and 2021, DESC incurred costs totaling $31 million, $33 million and $9 million, respectively.

Asset Retirement Obligations

DESC recognizes AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed, for which a legal obligation exists. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. Periodically, DESC assesses its AROs to determine if circumstances indicate that estimates of the amounts or timing of future cash flows associated with retirement activities have changed. AROs are adjusted when significant changes in the amounts or timing of future cash flows are identified. DESC reports accretion of AROs and depreciation on asset retirement costs as an adjustment to regulatory assets.

Nuclear Decommissioning

Based on a decommissioning cost study completed in 2020, DESC's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $808 million, stated in 2023 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under DESC's method of funding decommissioning costs, DESC transfers to an external trust fund the amounts collected through rates ($3 million in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer on an after-tax basis.

Cash, Restricted Cash and Equivalents

Cash, restricted cash and equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Restricted Cash and Equivalents

DESC may hold restricted cash and equivalent balances that consists of federal assistance funds to be used towards customer bill assistance.

The following table provides a reconciliation of the total cash, restricted cash and equivalents reported within DESC's Consolidated Balance Sheets to the corresponding amounts reported within DESC's Consolidated Statements of Cash Flows for the years ended December 31, 2023, 2022 and 2021:

	Cash, Restricted Cash and Equivalents at End/Beginning of Year			
	December 31, 2023	December 31, 2022	December 31, 2021	December 31, 2020
(millions)				
Cash and cash equivalents	**$ 1**	$ 11	$ 30	$ 5
Restricted cash and equivalents[1]	—	—	24	—
Cash, restricted cash and equivalents shown in the Consolidated Statements of Cash Flows	**$ 1**	$ 11	$ 54	$ 5

(1) Restricted cash and equivalent balances are presented within other current assets on the Consolidated Balance Sheets.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described in Note 4. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Unbilled revenues totaled $176 million and $188 million at December 31, 2023 and 2022, respectively.

DESC sells electricity and natural gas and provides distribution and transmission services to customers in South Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of DESC's customer base, which includes a large number of residential, commercial and industrial customers. Credit risk associated with accounts receivable is limited due to the large number of customers. DESC's exposure to potential concentrations of credit risk results primarily from amounts due from Santee Cooper related to the jointly owned nuclear generating facility at Summer. Such receivables represented approximately 10% of DESC's accounts receivable balance at December 31, 2023.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the South Carolina Commission.

Income Taxes

A consolidated federal income tax return is filed for Dominion Energy and its subsidiaries, including DESC. In addition, where applicable, combined income tax returns for Dominion Energy, including DESC, are filed in various states including South Carolina; otherwise, separate state income tax returns are filed.

DESC participates in an intercompany tax sharing agreement with Dominion Energy. Current income taxes are based on taxable income or loss and credits determined on a separate company basis.

Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion Energy consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

Accounting for income taxes involves an asset and liability approach. Deferred income tax assets and liabilities are provided, representing future effects on income taxes for temporary differences between the bases of assets and liabilities for financial reporting and tax purposes. Accordingly, deferred taxes are recognized for the future consequences of different treatments used for the reporting of transactions in financial accounting and income tax returns. The Company establishes a valuation allowance when it is more-likely-than-not that all, or a portion, of a deferred tax asset will not be realized. The Company did not have any valuation allowances recorded for the periods presented. Where the treatment of temporary differences is different for rate-regulated operations, a regulatory asset is recognized if it is probably that future revenues will be provided for the payment of deferred tax liabilities.

DESC recognizes positions taken, or expected to be taken, in income tax returns that are more likely than not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. At December 31, 2023 and 2022, the Company had $60 million and $67 million, respectively, of unrecognized tax benefits.

If it is not more-likely-than-not that a tax position, or some portion thereof, will be sustained, the related tax benefits are not recognized in the financial statements. Unrecognized tax benefits may result in an increase in income taxes payable, a reduction of income tax refunds receivable or changes in deferred taxes. Except when such amounts are presented net with amounts receivable from or amounts prepaid to tax authorities, noncurrent income taxes payable related to unrecognized tax benefits are classified in other deferred credits and other liabilities on the Consolidated Balance Sheets and current payables are included in taxes accrued on the Consolidated Balance Sheets.

DESC recognizes interest on underpayments and overpayments of income taxes in interest expense and interest income, respectively. Penalties are also recognized in other expenses.

DESC reflected benefits of $2 million and $21 million in interest expense in 2023 and 2021, respectively, and recognized a $7 million benefit in 2021 from the reversal of penalty expenses associated with the effective settlement of uncertain tax positions. Interest expense at DESC was $3 million in 2022. Interest income at DESC was less than $1 million in 2023, 2022 and 2021.

At December 31, 2023, the Company had an income tax-related affiliated payable of $15 million to Dominion Energy. This balance is expected to be paid to Dominion Energy.

At December 31, 2022, the Company had an income tax-related affiliated payable of $45 million to Dominion Energy. This balance was paid to Dominion Energy in 2023.

At December 31, 2021, the Company had an income tax-related affiliated receivable of $26 million from Dominion Energy. This balance was received from Dominion Energy in 2022.

At DESC, investment tax credits are deferred and amortized over the service lives of properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Regulatory Assets and Liabilities

The accounting for DESC's regulated electric and gas operations differs from the accounting for nonregulated operations in that DESC is required to reflect the effect of rate regulation in its Consolidated Financial Statements. For regulated businesses subject to federal or state cost-of-service rate regulation, regulatory practices that assign costs to accounting periods may differ from accounting methods generally applied by nonregulated companies. When it is probable that regulators will permit the recovery of current costs through future rates charged to customers, these costs that otherwise would be expensed by nonregulated companies are deferred as regulatory assets. Likewise, regulatory liabilities are recognized when it is probable that regulators will require customer refunds or other benefits through future rates or when revenue is collected from customers for expenditures that have yet to be incurred.

DESC evaluates whether or not recovery of its regulatory assets through future rates is probable as well as whether a regulatory liability due to customers is probable and makes various assumptions in its analyses. These analyses are generally based on:

- Orders issued by regulatory commissions, legislation and judicial actions;
- Past experience; and
- Discussions with applicable regulatory authorities and legal counsel.

Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. A regulatory liability, if considered probable, will be recorded in the period such assessment is made or reversed into earnings if no longer probable. See Note 3 to the Consolidated Financial Statements for additional information.

Derivative Instruments

DESC is exposed to the impact of market fluctuations in the price of electricity and natural gas it markets and purchases, as well as interest rate risk in its business operations. DESC uses derivative instruments such as physical forwards, options and swaps to manage commodity and/or interest rate risks of its business operations.

Derivative assets and liabilities are presented gross on DESC's Consolidated Balance Sheets. Derivative contracts representing unrealized gain positions are reported as derivative assets. Derivative contracts representing unrealized losses are reported as derivative liabilities. All derivatives, except those for which an exception applies, are required to be reported in the Consolidated Balance Sheets at fair value. One of the exceptions to fair value accounting, normal purchases and normal sales, may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Contracts for the future purchase of certain quantities of natural gas that no longer meet the criteria for the normal purchase normal sale exception are accounted for as derivative contracts. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance. See Fair Value Measurements below for additional information about fair value measurements and associated valuation methods for derivatives.

DESC's derivative contracts include over-the-counter transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter contracts contain contractual rights of setoff through master netting arrangements and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions are subject to collateral requirements. Types of collateral for over-the-counter contracts include cash, letters of credit and, in some cases, other forms of security, none of which are subject to restrictions.

DESC does not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. DESC had no margin assets or liabilities associated with cash collateral at December 31, 2023 and 2022. See Note 8 for further information about derivatives.

To manage price and interest rate risk, DESC holds derivative instruments that are not designated as hedges for accounting purposes. However, to the extent DESC does not hold offsetting positions for such derivatives, it believes these instruments represent economic hedges that mitigate its exposure to fluctuations in commodity prices or interest rates. All income statement activity, including amounts realized upon settlement, is presented in operating expenses and interest charges based on the nature of the underlying risk. For derivative instruments that are not accounted for as cash flow hedges, the cash flows from the derivatives are classified in operating cash flows.

Changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

DERIVATIVE INSTRUMENTS DESIGNATED AS HEDGING INSTRUMENTS

In accordance with accounting guidance pertaining to derivatives and hedge accounting, DESC designated a portion of its derivative instruments as cash flow hedges for accounting purposes. For derivative instruments that are accounted for as cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges- DESC used interest rate swaps to hedge its exposure to variable interest rates on long-term debt. For transactions in which DESC is hedging the variability of cash flows, changes in the fair value of the derivatives are reported in regulatory assets or liabilities. Any derivative gains or losses reported in regulatory assets or liabilities are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Pursuant to regulatory orders, interest rate derivatives entered into by DESC after October 2013 were not designated for accounting purposes as cash flow hedges, and fair value changes and settlement amounts related to them have been recorded as regulatory assets and liabilities. Settlement losses on swaps generally have been amortized over the lives of subsequent debt issuances, and gains have been amortized to interest charges or have been applied as otherwise directed by the South Carolina Commission.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of DESC's own nonperformance risk on its liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). DESC applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments. DESC applies credit adjustments to its derivative fair values in accordance with the requirements described above.

Inputs and Assumptions

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including industry publications, and to a lesser extent, broker quotes. When evaluating pricing information provided by Designated Contract Market settlement pricing, other pricing services, or brokers, DESC considers the ability to transact at the quoted price, i.e. if the quotes are based on an active market or an inactive market and to the extent which pricing models are used, if pricing is not readily available. If pricing information from external sources is not available, or if DESC believes that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the unobservable inputs are developed and substantiated using historical information, available market data, third-party data and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships and changes in third-party sources.

For options and contracts with option-like characteristics where observable pricing information is not available from external sources, DESC generally uses a model that considers time value, the volatility of the underlying commodities and other relevant assumptions when estimating fair value. For contracts with unique characteristics, DESC may estimate fair value using a discounted cash flow approach deemed appropriate in the circumstances and applied consistently from period to period. For individual contracts, the use of different valuation models or assumptions could have a significant effect on the contract's estimated fair value.

The inputs and assumptions used in measuring fair value include the following:

	Derivative Contracts	
Inputs and assumptions	**Commodity**	**Interest Rate**
Forward commodity prices	X	
Transaction prices	X	
Volumes	X	
Commodity location	X	
Interest rates	X	
Interest rate curves		X
Credit quality of counterparties and DESC	X	X
Credit enhancements	X	X
Time value	X	X
Notional value		X

Levels

DESC utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

•Level 1-Quoted prices (unadjusted) in active markets for identical assets and liabilities that it has the ability to access at the measurement date.
•Level 2-Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include commodity forwards and interest rate swaps.

•Level 3-Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for DESC consist of long-dated commodity derivatives and certain natural gas options.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

Debt Issuance Costs

DESC defers and amortizes debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. Deferred debt issuance costs are recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest charges. As permitted by regulatory authorities, gains or losses resulting from the refinancing or redemption of debt that are probable of recovery through future rates are deferred and amortized.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Statement of Operations Presentation

Revenues and expenses arising from regulated businesses are presented within operating income, and all other activities are presented within other income (expense), net.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered, or contracts settled and includes amounts yet to be billed to customers. DESC collects sales, consumption, consumer utility taxes and sales taxes; however, these amounts are excluded from revenue and are recorded as liabilities until they are remitted to the respective taxing authority.

The primary types of sales and service activities reported as operating revenue for DESC are as follows:

Revenue from Contracts with Customers

- **Regulated electric sales** consist primarily of state-regulated retail electric sales, and federally-regulated wholesale electric sales and electric transmission services;
- **Regulated gas sales** consist primarily of state-regulated natural gas sales and related distribution services; and
- **Other regulated revenue** consists primarily of miscellaneous service revenue from electric and gas distribution operations and sales of excess electric capacity and other commodities.

Other Revenue

- **Other revenue** consists primarily of alternative revenue programs, gains and losses from derivative instruments not subject to hedge accounting and lease revenues.

DESC records refunds to customers as required by the South Carolina Commission as a reduction to regulated electric sales or regulated gas sales, as applicable. Revenues from electric and gas sales are recognized over time, as the customers of DESC consume gas and electricity as it is delivered. Sales of products and services typically transfer control and are recognized as revenue upon delivery of the product or service. The customer is able to direct the use of, and obtain substantially all of the benefits from, the product at the time the product is delivered. The contract with the customer states the final terms of the sale, including the description, quantity and price of each product or service purchased. Payment for most sales and services varies by contract type, but is typically due within a month of billing.

DESC customers subject to an electric fuel cost recovery component or a PGA are billed based on a fuel or cost of gas factor calculated in accordance with cost recovery procedures approved by the South Carolina Commission and subject to adjustment periodically. Any difference between actual costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost recovery factors.

Certain amounts deferred for the WNA arise under specific arrangements with regulators rather than customers and are accounted for as an alternative revenue program. This alternative revenue is included within Other operating revenues, separate from revenue arising from contracts with customers, in the month such adjustments are deferred within regulatory accounts. As permitted, DESC has elected to reduce the regulatory accounts in the period when such amounts are reflected on customer bills without affecting operating revenues.

Performance obligations which have not been satisfied by DESC relate primarily to demand or standby service for natural gas. Demand or standby charges for natural gas arise when an industrial customer reserves capacity on assets controlled by the service provider and may use that capacity to move natural gas it has acquired from other suppliers. For all periods presented, the amount of revenue recognized by DESC for these charges is equal to the amount of consideration DESC has a right to invoice and corresponds directly to the value transferred to the customer.

Leases

DESC leases certain assets including vehicles, real estate, office equipment and other assets under both operating and finance leases. For operating leases, rent expense is recognized on a straight-line basis over the term of the lease agreement, subject to regulatory framework. Rent expense associated with operating leases, short-term leases and variable leases is primarily recorded in other operations and maintenance expense in the Consolidated Statements of Comprehensive Income (Loss). Amortization expense and interest charges associated with finance leases are deferred within regulatory assets in the Consolidated Balance Sheets and amortized into the Consolidated Statements of Comprehensive Income (Loss).

Certain leases include one or more options to renew, with renewal terms that can extend the lease from one to 70 years. The exercise of renewal options is solely at DESC's discretion and is included in the lease term if the option is reasonably certain to be exercised. A right-of-use asset and corresponding lease liability for leases with original lease terms of one year or less are not included in the Consolidated Balance Sheets, unless such leases contain renewal options that DESC is reasonably certain will be exercised.

The determination of the discount rate utilized has a significant impact on the calculation of the present value of the lease liability included in the Consolidated Balance Sheets. For DESC's leased assets, the discount rate implicit in the lease is generally unable to be determined from a lessee perspective. As such, DESC uses internally-developed incremental borrowing rates as a discount rate in the calculation of the present value of the lease liability. The incremental borrowing rates are determined based on an analysis of DESC's publicly available secured borrowing rates over various lengths of time that most closely correspond to DESC's lease maturities.

New Accounting Standards

Segment Disclosures

In November 2023, the FASB issued revised accounting guidance for reportable segments. The revised guidance requires disclosure of significant segment expenses and other segment items on an annual and interim basis and to provide in interim periods all disclosures about a reportable segment's profit or loss and assets that are currently required annually. Additionally, it requires disclosure of the title and position of the CODM. The revised guidance does not change how an entity identifies its operating segments, aggregates them or applies the quantitative thresholds to determine its reportable segments. The new standard is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted and requires retrospective application to all prior periods presented. DESC expects this revised guidance to only impact its disclosures with no impacts to its results of operations, cash flows or financial condition.

Income Tax Disclosures

In December 2023, the FASB issued revised accounting guidance for income taxes. The revised guidance requires disclosure of disaggregated information about an entity's effective tax rate reconciliation as well as additional information on income taxes paid. The new standard is effective for fiscal years beginning after December 15, 2024, with early adoption permitted and allows either prospective or retrospective application. DESC expects this revised guidance to only impact its disclosures with no impacts to its results of operations, cash flows or financial condition.

3. RATE AND OTHER REGULATORY MATTERS

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, DESC is involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for DESC to estimate a range of possible loss. For regulatory matters that DESC cannot estimate, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that DESC is able to estimate a range of possible loss. For regulatory matters that DESC is able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent DESC's maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on DESC's financial position, liquidity or results of operations.

Other Regulatory Matters

<u>South Carolina Electric Base Rate Case</u>

In August 2020, DESC filed its retail electric base rate case and schedules with the South Carolina Commission. In July 2021, DESC, the South Carolina Office of Regulatory Staff and other parties of record filed a comprehensive settlement agreement with the South Carolina Commission for approval. The comprehensive settlement agreement provided for a non-fuel, base rate increase of $62 million (resulting in a net increase of $36 million after considering an accelerated amortization of certain excess deferred income taxes) commencing with bills issued on September 1, 2021 and an authorized earned ROE of 9.50%. Additionally, DESC agreed to commit up to $15 million to forgive retail electric customer balances that were more than 60 days past due as of May 31, 2021 and provide $15 million for energy efficiency upgrades and critical health and safety repairs to customer homes. Pursuant to the comprehensive settlement agreement, DESC would not file a retail electric base rate case prior to July 1, 2023, such that new rates would not be effective prior to January 1, 2024, absent unforeseen extraordinary economic or financial conditions that may include changes in corporate tax rates. In July 2021, the South Carolina Commission approved the comprehensive settlement agreement and issued its final order in August 2021.

In connection with this matter, DESC recorded charges of $249 million ($187 million after-tax) reflected within impairment of assets and other charges (reflected in the Corporate and Other segment), including $237 million of regulatory assets associated with DESC's purchases of its first mortgage bonds during 2019 that are no longer probable of recovery under the settlement agreement, and $18 million ($14 million after-tax) reflected within other income (expense), net in its Consolidated Statements of Income for the year ended December 31, 2021.

On March 1, 2024, DESC filed a retail electric base rate request with the South Carolina Commission, requesting a net annual increase to revenues of $291 million. If approved, new rates would become effective in September 2024.

<u>Electric – Cost of Fuel</u>

DESC's retail electric rates include a cost of fuel component approved by the South Carolina Commission which may be adjusted periodically to reflect changes in the price of fuel purchased by DESC. In February 2023, DESC filed with the South Carolina Commission a proposal to increase the total fuel cost component of retail electric rates. DESC's proposed adjustment is designed to recover DESC's current base fuel costs, including its existing under-collected balance, over the 12-month period beginning with the first billing cycle of May 2023, along with a requested decrease to DESC's variable environmental and avoided capacity cost component. The net effect of the proposal is an annual increase of $176 million. In March 2023, DESC, the South Carolina Office of Regulatory Staff and another party of record filed a stipulation with the South Carolina Commission for approval to reduce the base fuel cost component reflecting a subsequent decrease in current fuel prices, resulting in a net annual increase of $121 million. In April 2023, the South Carolina Commission voted to approve the stipulation, with rates effective May 2023.

In February 2024, DESC filed with the South Carolina Commission a proposal to decrease the total fuel cost component of retail electric rates. DESC's proposed adjustment is designed to recover DESC's current base fuel costs, including its existing under-collected balance, over the 12-month period beginning with the first billing cycle of May 2024. In addition, DESC proposed an increase to its variable environmental and avoided capacity cost component. The net effect is a proposed annual decrease of $315 million. This matter is pending.

<u>Electric Transmission Project</u>

In March 2023, DESC filed an application with the South Carolina Commission requesting approval to construct and operate 19 miles of 230 kV transmission lines, a substation and associated facilities in Jasper County, South Carolina estimated to cost approximately $55 million. In July 2023, the South Carolina Commission voted to approve the request and issued its order in September 2023.

<u>Electric – Other</u>

DESC has approval for a DSM rider through which it recovers expenditures related to its DSM programs. In January 2023, DESC filed an application with the South Carolina Commission seeking approval to recover $46 million of costs and net lost revenues associated with these programs, along with an incentive to invest in such programs. DESC requested that rates be effective with the first billing cycle of May 2023. In April 2023, the South Carolina Commission approved the request, effective with the first billing cycle of May 2023. In January 2024, DESC filed an application with the South Carolina Commission seeking approval to recover $47 million of costs and net lost revenues associated with these programs, along with an incentive to invest in such programs. DESC requested that rates be effective with the first billing cycle of May 2024. This matter is pending.

DESC utilizes a pension costs rider approved by the South Carolina Commission which is designed to allow recovery of projected pension costs, including under-collected balances or net of over-collected balances, as applicable. The rider is typically reviewed for adjustment every 12 months with any resulting increase or decrease going into effect beginning with the first billing cycle in May. In April 2023, the South Carolina Commission approved DESC's requested adjustment to this rider to increase annual revenue by $24 million. In February 2024, DESC requested that the South Carolina Commission approve an adjustment to this rider to increase annual revenue by $9 million. This matter is pending.

<u>Natural Gas Rates</u>

In March 2023, DESC filed its natural gas base rate case and schedules with the South Carolina Commission. DESC proposed a rate increase of $19 million effective October 2023. The base rate increase was proposed to recover significant investment in distribution infrastructure for the benefit of customers. The proposed rates would provide for an ROE of 10.38% compared to the currently authorized ROE of 10.25%. In addition, DESC elected to continue applicability of the Natural Gas Rate Stabilization Act, which allows for the adjustment of natural gas base rates annually, to its future rates and charges. In September 2023, DESC, the South Carolina Office of Regulatory Staff and other parties of record filed a stipulation agreement with the South Carolina Commission for approval. The stipulation agreement provides for a rate increase of $9 million commencing with bills rendered in October 2023, and an authorized ROE of 9.49%. Pursuant to the stipulation agreement, DESC would not file a natural gas base rate case prior to April 1, 2026, such that new rates would not be effective prior to October 1, 2026, absent unforeseen extraordinary economic or financial conditions that may include changes in corporate tax rates. In September 2023, the South Carolina Commission approved the stipulation agreement and issued its final order in October 2023.

DESC's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. DESC's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the South Carolina Commission.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, DESC has recorded regulatory assets and regulatory liabilities which are summarized in the following table.

Except for NND Project costs and certain other unrecovered costs reference herein, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

At December 31,		2023		2022
(millions)				
Regulatory assets:				
NND Project costs(1)	$	**138**	$	138
AROs(2)		**44**		8
Deferred employee benefit plan costs(3)		**11**		4
Other unrecovered plant(4)		**19**		17
DSM programs(5)		**22**		21
Cost of fuel and purchased gas under-collections(6)		**154**		508
Other		**52**		46
Regulatory assets - current		**440**		742
NND Project costs(1)		**1,949**		2,088
AROs(2)		**360**		363
Deferred employee benefit plan costs(3)		**118**		161
Interest Rate Hedges (7)		**168**		167
Other unrecovered plant(4)		**66**		58
DSM programs(5)		**46**		41
Environmental remediation costs(8)		**34**		37
Deferred storm damage costs(9)		**40**		43
Deferred transmission operating costs(10)		**74**		75
Derivatives (11)		**100**		105
Other(12)		**131**		131
Regulatory assets - noncurrent		**3,086**		3,269
Total regulatory assets	$	**3,526**	$	4,011
Regulatory liabilities:				
Monetization of guaranty settlement(13)	$	**67**	$	67
Income taxes refundable through future rates(14)		**36**		33
Reserve for refunds to electric utility customers(15)		**83**		100
Derivatives (11)		**12**		43
Other		**6**		6
Regulatory liabilities - current		**204**		249
Monetization of guaranty settlement(13)		**635**		702
Income taxes refundable through future rates(14)		**810**		842
Asset removal costs(16)		**628**		581
Reserve for refunds to electric utility customers(15)		**237**		325
Derivatives (11)		**229**		276
Other		**6**		14
Regulatory liabilities - noncurrent		**2,545**		2,740
Total regulatory liabilities	$	**2,749**	$	2,989

(1) Reflects expenditures associated with the NND Project, which pursuant to the SCANA Merger Approval Order, will be recovered from electric service customers over a 20-year period ending in 2039.

(2) Represents uncollected costs, including deferred depreciation and accretion expense related to legal obligations associated with the future retirement of generation, transmission and distribution properties. The AROs primarily relate to DESC's electric generating facilities, including Summer, and are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 105 years.

(3) Employee benefit plan costs have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific South Carolina Commission regulatory orders. DESC expects to recover deferred pension costs through utility rates over periods through 2044. DESC expects to recover other deferred benefit costs through utility rates, primarily over average service periods of participating employees up to 11 years.

(4) Represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. DESC is amortizing these amounts through cost of service rates following depreciation amounts that were designed to recover the retired units cost over their previous estimated remaining useful lives, which has been estimated to be through 2025. Based on current projections of remaining decommissioning costs, projected recovery is expected to extend through 2033. In addition, amounts include unrecovered costs of existing meters and equipment retired from service prior to being fully depreciated as part of the Advanced Metering Infrastructure project, which are being recovered through rates through 2028. This amount also includes certain inventory and preliminary survey and investigation charges being amortized over five years related to the transition or conversion from coal to gas fired generation at certain facilities.

(5) Represents deferred costs associated with electric demand reduction programs, and such deferred costs are currently being recovered over three years through an approved rate rider.

(6) Represents amounts under- or over-collected from customers pursuant to the cost of fuel and purchased gas components approved by the South Carolina Commission.

(7) Represents the changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges. The amounts recorded are expected to be amortized to interest expense over the lives of the underlying debt through 2065.

(8) Reflects amounts associated with the assessment and clean-up of sites currently or formerly owned by DESC. Such remediation costs are expected to be recovered over periods of up to 25 years. See Note 12 for additional information.

(9) Represents storm restoration costs for which DESC expects to receive future recovery through customer rates over approximately 10 years pursuant to the settlement agreement approved in DESC's retail electric base rate case. Unamortized amounts are included in rate base and are earning a current return.

(10) Includes deferred depreciation and property taxes associated with certain transmission assets for which DESC expects recovery from customers through future rates over approximately 42 years pursuant to the settlement agreement approved in DESC's retail electric base rate case. Unamortized amounts are included in rate base and earning a current return.

(11) Represents changes in the fair value of derivatives, excluding separately presented interest rate hedges, that following settlement are expected to be recovered from or refunded to customers.

(12) Various other regulatory assets are expected to be recovered through rates over varying periods through 2078.

(13) Represents proceeds related to the monetization of the Toshiba Settlement. In accordance with the SCANA Merger Approval Order, this balance, net of amounts that may be required to satisfy liens, will be refunded to electric customers over a 20-year period ending in 2039.

(14) Includes (i) excess deferred income taxes arising from the remeasurement of deferred income taxes in connection with the enactment of the 2017 Tax Reform Act (certain of which are protected under normalization rules and will be amortized over the remaining lives of related property, and certain of which will be amortized to the benefit of customers over prescribed periods as instructed by regulators) and (ii) deferred income taxes arising from investment tax credits, offset by (iii) deferred income taxes that arise from utility operations that have not been included in customer rates (a portion of which relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to 85 years). See Note 7 for additional information.

(15) Reflects amounts previously collected from retail electric customers of DESC for the NND Project to be credited to customers over an estimated 11-year period effective February 2019 in connection with the SCANA Merger Approval Order.

(16) Represents estimated net collections through depreciation rates of amounts to be expended for the removal of assets in the future.

Regulatory assets have been recorded based on the probability of their recovery. All regulatory assets represent incurred costs that may be deferred under GAAP for regulated operations. The South Carolina Commission or FERC has reviewed and approved through specific orders certain of the items shown as regulatory assets. In addition, regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by one of these regulatory agencies. While such costs are not currently being recovered, management believes that they would be allowable under existing rate-making concepts embodied in rate orders or applicable state law and expects to recover these costs through rates in future periods.

4. OPERATING REVENUE

DESC's operating revenue consists of the following:

Year Ended December 31,	2023				2022				2021			
(millions)	Electric		Gas		Electric		Gas		Electric		Gas	
Customer class:												
Residential	$	**1,160**	$	**268**	$	1,375	$	303	$	1,211	$	245
Commercial		**820**		**129**		968		184		834		133
Industrial		**372**		**77**		533		166		424		103
Other		**150**		**24**		203		23		157		25
Revenues from contracts with customers		**2,502**		**498**		3,079		676		2,626		506
Other revenues		**27**		**1**		27		1		13		1
Total Operating Revenues	$	**2,529**	$	**499**	$	3,106	$	677	$	2,639	$	507

Contract liabilities represent the obligation to transfer goods or services to a customer for which consideration has already been received from the customer. DESC had contract liability balances of $7 million and $12 million at December 31, 2023 and 2022, respectively. For the years ended December 31, 2023 and 2022, DESC recognized revenue of $9 million and $6 million, respectively, from the beginning contract liability balances as DESC fulfilled its obligations to provide service to its customers. Contract liabilities are recorded in customer deposits and customer prepayments in the Consolidated Balance Sheets.

Contract Costs

In limited instances, DESC provides economic development grants intended to support economic growth within DESC's electric service territory and defers such grants as regulatory assets on the Consolidated Balance Sheets. Whenever these grants are contingent on a customer entering into a long-term electric supply contract with DESC such costs are deferred and amortized on a straight-line basis over the term of the related service contract, which generally ranges from ten to 15 years.

Balances and activity related to contract costs deferred as regulatory assets were as follows:

	Regulatory Assets	
(millions)	**2023**	2022
Beginning balance, January 1	**$ 9**	$ 11
Additional costs	**3**	—
Amortization	**(1)**	(2)
Ending balance, December 31	**$ 11**	$ 9

5. EQUITY

For all periods presented, DESC's authorized shares of common stock, no par value, were 50 million, of which 40.3 million were issued and outstanding, and DESC's authorized shares of preferred stock, no par value, were 20 million, of which 1,000 shares were issued and outstanding. All outstanding shares of common and preferred stock are held by SCANA.

In 2022, Dominion Energy issued $72 million of shares of Dominion Energy common stock to partially satisfy DESC's remaining obligation under a settlement agreement with the SCDOR discussed in Note 12. In connection with this transaction, DESC recorded an equity contribution from Dominion Energy.

In 2021, Dominion Energy issued $104 million of shares of Dominion Energy common stock to satisfy DESC's obligation under a settlement agreement for the FILOT litigation discussed in Note 12. Additionally, in 2021, Dominion Energy issued $45 million of shares of Dominion Energy common stock to satisfy DESC's obligation for the initial payment under a settlement agreement with the SCDOR discussed in Note 12. In connection with these transactions, DESC recorded equity contributions from Dominion Energy.

In 2021, DESC returned $150 million of capital previously contributed from SCANA which had been funded by Dominion Energy.
DESC's bond indenture under which it issues first mortgage bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its Surplus (as defined in the bond indenture) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, pursuant to the SCANA Merger Approval Order, the amount of any DESC dividends paid must be reasonable and consistent with the long-term payout ratio of the electric utility industry and gas distribution industry.

At December 31, 2023, DESC's retained earnings exceed the balance established by the Federal Power Act as a reserve on earnings attributable to hydroelectric generation plants. As a result, DESC is permitted to pay dividends without additional regulatory approval provided that such amounts would not bring the retained earnings balance below the established threshold.

6. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted-average coupon rates and maturities at December 31, 2023 and 2022 is as follows:

At December 31,	**2023 Weighted-average Coupon**[(1)]	**2023**	2022
(millions, except percentages)			
DESC:			
First Mortgage Bonds, 2.30% to 6.625%, due 2028 to 2065	**5.23 %**	**$ 4,134**	$ 3,634
Tax-Exempt Financings:[(2)]			
Variable rate due 2038	**3.87 %**	**35**	35
3.625% and 4.00%, due 2028 and 2033	**3.90 %**	**54**	54
Other	**3.61 %**	**1**	1
Total principal		**4,224**	3,724
Unamortized discount, premium and debt issuance costs, net		**(38)**	(32)
Finance leases		**4**	6
Total long-term debt		**$ 4,190**	$ 3,698

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2023.
(2) Industrial revenue bonds totaling $68 million are secured by letters of credit that expire, subject to renewal, in the fourth quarter of 2024.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2023, were as follows:

(millions, except percentages)	2024	2025	2026	2027	2028	Thereafter	Total
First Mortgage Bonds	**$ —**	**$ —**	**$ —**	**$ —**	**$ 53**	**$ 4,081**	**$ 4,134**
Tax-Exempt Financings	**—**	**—**	**—**	**—**	**39**	**51**	**90**
Total	**$ —**	**$ —**	**$ —**	**$ —**	**$ 92**	**$ 4,132**	**$ 4,224**
Weighted-average coupon					**4.14 %**	**5.23 %**	

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

DESC is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2023, the Bond Ratio was approximately 5.

Short-Term Debt

DESC's short-term financing is supported through its access as co-borrower to Dominion Energy's $6.0 billion joint revolving credit facility, which can be used for working capital, as support for the combined commercial paper programs of DESC, Dominion Energy, Virginia Power and Questar Gas, and for other general corporate purposes.

DESC's share of commercial paper and letters of credit outstanding under its joint credit facility with Dominion Energy, were as follows:

(millions)	**Facility Limit**	**Outstanding Commercial Paper**[(1)]	**Outstanding Letters of Credit**
At December 31, 2023			
Joint revolving credit facility[(2)]	**$ 1,000**	**$ 254**	**$ —**
At December 31, 2022			
Joint revolving credit facility[(2)]	**$ 1,000**	**$ 249**	**$ —**

(1) The weighted average interest rate of the outstanding commercial paper supported by the credit facility was 5.70% and 4.76% at December 31, 2023 and 2022, respectively.
(2) A maximum of $1.0 billion of the facility is available to DESC, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion Energy, Virginia Power and Questar Gas. A sub-limit for DESC is set within the facility limit but can be changed at the option of the co-borrowers multiple times per year. At December 31, 2023, the sub-limit for DESC was $500 million. If DESC has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term borrowings from Dominion Energy. This credit facility matures in June 2026, with the potential to be extended by the borrowers to June 2028. The credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.0 billion (or the sub-limit, whichever is less) of letters of credit.

In March 2023, FERC granted DESC authority through March 2025 to issue short-term indebtedness (pursuant to Section 204 of the Federal Power Act) in amounts not to exceed $2.2 billion outstanding with maturity dates of one year or less. At December 31, 2023, DESC had issued $254 million in commercial paper under its joint credit facility with Dominion Energy as disclosed above and had drawn on $135 million of its intercompany credit facility with Dominion Energy, as permitted by this FERC authorization.

DESC is obligated with respect to an aggregate of $68 million of industrial revenue bonds which are secured by letters of credit. These letters of credit expire, subject to renewal, in the fourth quarter of 2024.

DESC and Fuel Company each have intercompany credit facilities with Dominion Energy with a maximum capacity of $900 million and $400 million, respectively. At December 31, 2023 and 2022, DESC and Fuel Company collectively had borrowings outstanding under these agreements totaling $408 million and $769 million, respectively, which are recorded in affiliated and related party payables in DESC's Consolidated Balance Sheets. For the years ended December 31, 2023, 2022 and 2021, DESC recorded interest charges of $45 million, $19 million and less than $1 million, respectively.

Fuel Company participated in a SCANA utility money pool until January 2021, when that utility money pool was closed. Money pool borrowings and investments bore interest at short-term market rates. For the year ended December 31, 2021 DESC recorded interest income from money pool transactions of less than $1 million, and for the same period DESC recorded interest expense from money pool transactions of less than $1 million.

7. INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty since tax authorities may interpret the laws differently. DESC is routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

As indicated in Note 2, DESC's operations, including accounting for income taxes, are subject to regulatory accounting treatment. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and were recorded as either an increase to a regulatory asset or liability. See Note 3 for more information and current year developments.

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

Year Ended December 31,		2023		2022		2021
(millions)						
Current:						
Federal	$	**84**	$	(69)	$	(42)
State		**(65)**		—		(43)
Total current benefit		**19**		(69)		(85)
Deferred:						
Federal						
Taxes before operating loss carryforwards, investment tax credits and tax reform		**(70)**		132		43
Tax utilization expense of operating loss carryforwards		**43**		33		34
State		**88**		31		17
Total deferred expense		**61**		196		94
Investment tax credit-amortization		**(1)**		(1)		(1)
Total income tax expense	$	**79**	$	126	$	8

Subsequent to the SCANA Combination, DESC's annual utilization of its net operating losses are restricted by the tax law. However, in certain circumstances, the utilization may be increased if SCANA recognizes built-in gains on certain sales of assets.

For continuing operations including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to DESC's effective income tax rate as follows:

Year Ended December 31,	2023	2022	2021
U.S. statutory rate	**21.0 %**	21.0 %	21.0 %
Increases (reductions) resulting from:			
State taxes, net of federal benefit	**4.2**	4.7	5.7
AFUDC - equity	**—**	—	(0.4)
Amortization of federal investment tax credits	**(0.3)**	(0.2)	(0.6)
Reversal of excess deferred income taxes	**(4.8)**	(4.7)	(8.6)
Changes in unrecognized tax benefits	**(2.3)**	—	(15.6)
Prior period adjustments	**—**	—	1.3
Other	**(0.3)**	(0.2)	0.8
Effective tax rate	**17.5 %**	20.6 %	3.6 %

DESC's 2023 effective tax rate reflects an income tax benefit of $11 million from the effective settlement of a position that management believed was reasonably possible to occur.

In December 2021, unrecognized tax benefits related to several state uncertain tax positions were effectively settled through negotiations with the taxing authority. Management believed it was reasonably possible these unrecognized tax benefits could decrease through settlement negotiations or payments during 2021, however no income tax benefits could be recognized unless or until the positions were effectively settled. Resolution of these uncertain tax positions decreased income tax expense by $34 million.

DESC's deferred income taxes consist of the following:

At December 31,		2023		2022
(millions)				
Deferred income taxes:				
Total deferred income tax assets	$	**866**	$	1,066
Total deferred income tax liabilities		**2,053**		2,170
Total net deferred income tax liabilities	$	**1,187**	$	1,104
Total deferred income taxes:				
Depreciation method and plant basis differences	$	**1,125**	$	1,095
Excess deferred income taxes		**(204)**		(212)
Unrecovered nuclear plant cost		**450**		479
DESC rate refund		**(67)**		(89)
Toshiba settlement		**(147)**		(162)
Nuclear decommissioning		**(51)**		(44)
Deferred state income taxes		**258**		259
Federal benefit of deferred state income taxes		**(54)**		(54)
Deferred fuel, purchased energy and gas costs		**32**		107
Pension benefits		**35**		50
Other postretirement benefits		**(17)**		(32)
Loss and credit carryforwards		**(221)**		(352)
Other		**48**		59
Total net deferred income tax liabilities	$	**1,187**	$	1,104
Deferred Investment Tax Credits-Regulated Operations		**13**		14
Total Deferred Taxes and Deferred Investment Tax Credits	$	**1,200**	$	1,118

At December 31, 2023, DESC had the following deductible loss and credit carryforwards:

(millions)		Deductible Amount		Deferred Tax Asset	Expiration Period
Federal losses	$	**533**	$	**112**	**2037**
Federal production and other credits		**—**		**30**	**2041-2043**
State losses		**878**		**44**	**2037-2042**
State investment and other credits		**—**		**35**	**2026-2031**
Total	$	**1,411**	$	**221**	

A reconciliation of changes in DESC's unrecognized tax benefits follows:

(millions)		2023		2022
Balance at January 1	$	**67**	$	61
Increases-prior period positions		**4**		6
Decreases-prior period positions		**(11)**		(1)
Increases-current period positions		**—**		1
Settlements with tax authorities		**—**		—
Balance at December 31	$	**60**	$	67

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. If recognized, all the unrecognized tax benefits would impact the effective tax rate.

The statute is closed for IRS examination of years prior to 2013. The IRS is currently examining DESC's federal returns from 2013 through 2017. DESC is no longer subject to state and local income tax examinations by tax authorities for years prior to 2020.

It is reasonably possible that these unrecognized tax benefits may decrease by $27 million within the next twelve months. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by $14 million. Otherwise, with regard to 2023 and prior years, DESC cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2024.

DESC is also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if DESC utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

8. DERIVATIVE FINANCIAL INSTRUMENTS

See Note 2 for DESC's accounting policies, objectives, and strategies for using derivative instruments. See Notes 2 and 9 for further information about fair value measurements and associated valuation methods for derivatives.

The table below presents derivative balances by type of financial instrument, if the gross amounts recognized in the Consolidated Balance Sheets were netted with derivative instruments and cash collateral received or paid. DESC's commodity derivative assets are not subject to a master netting agreement or similar arrangement. DESC did not have any derivative instruments in a liability position as of December 31, 2023 and 2022.

	December 31, 2023				December 31, 2022			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Gross Assets Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Gross Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Interest rate contracts:								
Over-the-counter	$ **—**	$ **—**	$ **—**	$ **—**	$ 1	$ —	$ —	$ 1
Total derivatives	$ **—**	$ **—**	$ **—**	$ **—**	$ 1	$ —	$ —	$ 1

Volumes

The following table presents the volume of derivative activity at December 31, 2023. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions.

(millions)	Current	Noncurrent
Electricity (MWh):		
Fixed price	**2**	**22**
Interest rate(1)	$ **—**	$ **35**

(1) Maturity is determined based on final settlement period.

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of derivatives and where they are presented in the Consolidated Balance Sheets:

(millions)		**Fair Value - Derivatives not under Hedge Accounting**
At December 31, 2023		
Current Assets		
Commodity	$	**9**
Total current derivative assets (1)		**9**
Noncurrent Assets		
Commodity		**167**
Total noncurrent derivative assets (2)		**167**
Total derivative assets	$	**176**
At December 31, 2022		
Current Assets		
Commodity	$	41
Total current derivative assets (1)		41
Noncurrent Assets		
Commodity		210
Interest rate		1
Total noncurrent derivative assets (2)		211
Total derivative assets	$	252

(1) Current derivative assets are presented in other current assets in DESC's Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred debits and other assets in DESC's Consolidated Balance Sheets.

The following tables present the gains and losses on derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Comprehensive Income:

Derivatives in Cash Flow Hedging Relationships

(millions)	**Increase (Decrease) in Derivatives Subject to Regulatory Treatment(1)**
Year Ended December 31, 2023	

Year Ended December 31, 2023		
Derivative type and location of gains (losses):		
Interest rate	**$**	**1**
Total	**$**	**1**
Year Ended December 31, 2022		
Derivative type and location of gains (losses):		
Interest rate	$	1
Total	$	1
Year Ended December 31, 2021		
Derivative type and location of gains (losses):		
Interest rate	$	4
Total	$	4

(1) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/ liabilities have no associated effect in the Consolidated Statements of Comprehensive Income.

Derivatives Not designated as Hedging Instruments

(millions)	Amount of Gain (Loss) Recognized in Income on Derivatives[1]					
Year Ended December 31,		**2023**		2022		2021
Derivative type and location of gains (losses):						
Commodity contracts:						
Purchased power	**$**	**6**		77		8
Interest rate contracts:						
Interest charges		**(2)**		(2)		(2)
Total	**$**	**4**	$	75	$	6

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in the Consolidated Statements of Comprehensive Income.

9. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

DESC's fair value measurements are made in accordance with the policies discussed in Note 2. See Note 8 for additional information about DESC's derivative and hedge accounting activities.

Level 3 Valuations

DESC enters into physical forwards contracts, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical forwards contracts. The discounted cash flow model for forwards calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. For Level 3 fair value measurements, certain forward market prices are considered unobservable.

The following table presents DESC's quantitative information about Level 3 fair value measurements at December 31, 2023. The range and weighted average are presented in dollars for market price inputs.

		Fair Value (millions)	Valuation Techniques	Unobservable Input	Range	Weighted Average[1]
Assets						
Physical forwards:						
Electricity	**$**	**176**	Discounted cash flow	Market price (per MWh)[2]	27-94	48
Total assets	**$**	**176**				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Recurring Fair Value Measurements

Fair value disclosures for assets held in DESC's pension plan are presented in Note 11.

The following table presents DESC's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

		Level 1		Level 2		Level 3		Total
(millions)								
At December 31, 2023								
Assets								
Commodity	**$**	**—**	**$**	**—**	**$**	**176**	**$**	**176**
Total assets	**$**	**—**	**$**	**—**	**$**	**176**	**$**	**176**
At December 31, 2022								
Assets								
Commodity	$	—	$	—	$	251	$	251
Interest rate		—		1		—		1
Total assets	$	—	$	—	$	251	$	252

The following table presents the net change in DESC's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

		2023		2022
(millions)				
Balance at January 1,	**$**	**251**	$	148
Total realized and unrealized gains (losses):				
Included in earnings:				
Purchased power		**6**		77
Included in regulatory assets/liabilities		**(75)**		103
Settlements		**(6)**		(77)
Balance at December 31	**$**	**176**	$	251

There are no unrealized gains and losses included in earnings in the Level 3 fair value category related to assets/liabilities still held at the reporting date for the years ended December 31, 2023 and 2022.

Fair Value of Financial Instruments

Substantially all of DESC's financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of financial instruments classified within current assets and current liabilities are representative of fair value because of the short-term nature of these instruments. For financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

At December 31,	2023		2022	
(millions)	**Carrying Amount**	**Estimated Fair Value[(1)]**	Carrying Amount	Estimated Fair Value[(1)]
Long-term debt[(2)]	**$ 4,186**	**$ 4,268**	$ 3,691	$ 3,581

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. All fair value measurements are classified as Level 2. The carrying amount of debt issuances with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.
(2) Carrying amount includes current portions included in securities due within one year and amounts which represent the unamortized debt issuance costs and discount or premium.

10. ASSET RETIREMENT OBLIGATIONS

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to DESC's regulated utility operations. As of December 31, 2023 and 2022, DESC has recorded AROs of $311 million and $299 million, respectively, for nuclear plant decommissioning. In addition, DESC has recorded AROs of $402 million and $313 million at December 31, 2023 and 2022, respectively, for other conditional obligations primarily related to other generation and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

(millions)	2023	2022
Beginning balance	**$ 612**	$ 583
Liabilities incurred	**7**	6
Liabilities settled	**(14)**	(1)
Accretion expense	**28**	25
Revisions in estimated cash flows[(1)]	**80**	—
Other	**—**	(1)
Ending balance	**$ 713**	$ 612

(1) In 2023, there was an increase in estimated costs associated with certain coal-fired generating units, including revisions following the approval of closure plans for a facility previously taken out of service.

11. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. DESC participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently through December 31, 2013. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the final average pay formula continued to accrue through December 31, 2023, after which date eligible participants began accruing benefits under the cash balance formula.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. DESC participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent-sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations
The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
(millions)	2023	2022	2023	2022
Beginning balance	**$ 580**	$ 702	**$ 121**	$ 171
Service cost	**8**	8	**1**	1
Interest cost	**33**	21	**8**	6
Amendments	**1**	—	**—**	—
Actuarial (gain) loss	**1**	(105)	**1**	(44)
Benefits paid	**(39)**	(46)	**(11)**	(13)
Ending balance	**$ 584**	$ 580	**$ 120**	$ 121

The accumulated benefit obligation for pension benefits for DESC was $579 million and $578 million at December 31, 2023 and 2022, respectively. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2023	2022	2023	2022
Annual discount rate used to determine benefit obligation	**5.39 %**	5.69 %	**5.42 %**	5.70 %
Assumed annual rate of future salary increases for projected benefit obligation	**3.54 %**	3.93 %	**N/A**	N/A
Crediting interest rate for cash balance plans	**4.14 %**	4.44 %	**N/A**	N/A

DESC's pension benefit obligations include a loss of $1 million in 2023 resulting primarily from a $10 million loss due to a decrease in the discount rate that was offset by a $9 million gain from other experience. DESC's pension benefit obligations include a gain of $105 million in 2022 resulting primarily from an increase in the discount rate and a completed experience study. Actuarial losses recognized in DESC's other postretirement benefit obligations include a $1 million loss in 2023 resulting from a $4 million loss due to a decrease in the discount rate that was offset by a $3 million gain from other experience. Actuarial gains recognized in DESC's other postretirement benefit obligations include a $44 million gain in 2022 resulting from an increase in the discount rate.

A 7.00% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2023. The rate was assumed to decrease gradually to 5.0% in 2031 and to remain at that level thereafter.

Funded Status

	Pension Benefits		Other Postretirement Benefits	
At December 31,	2023	2022	2023	2022
(millions)				
Fair value of plan assets	**$ 588**	$ 561	**$ —**	$ —
Benefit obligation	**584**	580	**120**	121
Funded status	**$ 4**	$ (19)	**$ (120)**	$ (121)

Amounts recognized on the consolidated balance sheets were as follows:

At December 31,	Pension Benefits 2023	Pension Benefits 2022	Other Postretirement Benefits 2023	Other Postretirement Benefits 2022
(millions)				
Noncurrent assets	$ 4	$ —	$ —	$ —
Current liability	—	—	(11)	(11)
Noncurrent liability	—	(19)	(109)	(110)

Amounts recognized in AOCI were as follows:

At December 31,	Pension Benefits 2023	Pension Benefits 2022	Other Postretirement Benefits 2023	Other Postretirement Benefits 2022
(millions)				
Net actuarial (gain) loss	$ 2	$ 3	$ (1)	$ (1)

Amounts recognized in regulatory assets were as follows:

At December 31,	Pension Benefits 2023	Pension Benefits 2022	Other Postretirement Benefits 2023	Other Postretirement Benefits 2022
(millions)				
Net actuarial (gain) loss	$ 126	$ 164	$ (41)	$ (46)
Prior service cost	1	—	—	—
Total	$ 127	$ 164	$ (41)	$ (46)

In connection with the joint ownership of Summer, costs related to pensions attributable to Santee Cooper as of both December 31, 2023 and 2022 totaled $19 million and $21 million and were recorded within deferred debits. Costs related to other postretirement benefits attributable to Santee Cooper as of December 31, 2023 and 2022 totaled $10 million and $9 million and were recorded within deferred debits.

Changes in Fair Value of Plan Assets

(millions)	Pension Benefits 2023	Pension Benefits 2022
Beginning Balance	$ 561	$ 768
Actual return (loss) on plan assets	66	(161)
Benefits paid	(39)	(46)
Ending Balance	$ 588	$ 561

Investment Policies and Strategies

Strategic investment policies are established for DESC's prefunded benefit plans based upon periodic asset/liability studies. Factors considered in setting the investment policy include employee demographics, liability growth rates, future discount rates, the funded status of the plans and the expected long-term rate of return on plan assets. Deviations from the plans' strategic allocation are a function of DESC's assessments regarding short-term risk and reward opportunities in the capital markets and/or short-term market movements which result in the plans' actual asset allocations varying from the strategic target asset allocations. Through periodic rebalancing, actual allocations are brought back in line with the target. Future asset/liability studies will focus on strategies to further reduce pension and other postretirement plan risk, while still achieving attractive levels of returns. Financial derivatives may be used to obtain or manage market exposures and to hedge assets and liabilities.

DESC's overall objective for investing its pension plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. To minimize risk, funds are diversified among asset classes, securities, active and passive investment strategies and investment advisors. The strategic target asset allocations for DESC's pension fund are: 45% global equities, 53% fixed income and 2% cash. Global equities include investments in U.S. and non-U.S. companies, developed and emerging markets and small and large cap companies. The split between U.S. and non-U.S. companies is roughly 60% U.S./40% Non-U.S. Fixed income includes investments in corporate debt instruments of companies from diversified industries and U.S. Treasuries. Equity and fixed income investments are in individual securities, mutual funds and exchange traded funds.

DESC also utilizes commingled funds/collective trust funds as an investment vehicle for its defined benefit plans. A commingled fund/collective trust fund is a pooled fund operated by a bank, trust company, or investment firm for investment of the assets of various organizations and individuals in a diversified portfolio. Commingled funds/collective trust funds are funds of grouped assets that follow various investment strategies.

For 2024, the expected long-term rate of return on assets will be 7.00%. DESC determines the expected long-term rates of return on plan assets for its pension plans by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset classes' volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major capital market assumptions; and
- Investment allocation of plan assets.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2023 and 2022, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

At December 31,	2023				2022			
(millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5	$ —	$ 2	$ —	$ 2
Corporate debt instruments	—	137	—	137	—	137	—	137
Government and other debt instruments	—	14	—	14	—	18	—	18
Total recorded at fair value	$ 4	$ 152	$ —	$ 156	$ —	$ 157	$ —	$ 157
Assets recorded at NAV(1)								
Common/collective trust funds				436				417
Total recorded at NAV				$ 436				$ 417
Total investments(2)				$ 592				$ 574

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2) Excludes net assets related to pending sales of securities of $1 million, net accrued income of $1 million, and includes net assets related to pending purchases of securities of $6 million at December 31, 2023. Excludes net assets related to pending sales of securities of $1 million, net accrued income of $1 million, and includes net assets related to pending purchases of securities of $15 million at December 31, 2022.

For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. U.S. Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt instruments and government and other debt instruments are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. In addition, corporate debt instruments include investments in open-end mutual funds registered with the SEC that invest in corporate debt instruments. Commingled funds/common collective trust assets are valued at NAV, which are determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such funds by dividing the funds' net assets at fair value by the units outstanding at each valuation date.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:

Expected Benefit Payments

(millions)	Pension Benefits	Other Postretirement Benefits
2024	$ 47	$ 11
2025	47	11
2026	45	11
2027	44	11
2028	46	11
2029-2033	236	55

Pension Plan Contributions

Under its funding policies, DESC evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, DESC determines the amount of contributions for the current year, if any, at that time. DESC made no contributions to the pension trust in 2023, 2022 or 2021. DESC expects to make $8 million of minimum required contributions to its qualified pension plan in 2024 and expects to receive reimbursement for such contributions from Santee Cooper.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit (Credit) Cost

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2023**	2022	2021	**2023**	2022	2021
(millions)						
Service cost	**$ 8**	$ 8	$ 9	**$ 1**	$ 1	$ 1
Interest cost	**33**	21	20	**8**	6	6
Expected return on assets	**(34)**	(49)	(48)	**—**	—	—
Amortization of actuarial losses	**12**	1	6	**(4)**	—	—
Net periodic benefit (credit) cost	**$ 19**	$ (19)	$ (13)	**$ 5**	$ 7	$ 7

In connection with regulatory orders, DESC recovers current pension costs through a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations. For retail electric operations, current pension expense is recognized based on amounts collected through a rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, DESC amortizes certain previously deferred pension costs. See Note 3.

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2023**	2022	2021	**2023**	2022	2021
(millions)						
Current year actuarial (gain) loss	**$ (1)**	$ 2	$ (3)	**$ —**	$ (1)	$ —
Total recognized in other comprehensive income	**$ (1)**	$ 2	$ (3)	**$ —**	$ (1)	$ —

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2023**	2022	2021	**2023**	2022	2021
(millions)						
Current year actuarial (gain) loss	**$ (27)**	$ 95	$ (39)	**$ 2**	$ (41)	$ (6)
Amortization of actuarial gain (loss)	**(11)**	(1)	(5)	**3**	—	—
Current year prior service cost	**1**	—	—	**—**	—	—
Total recognized in regulatory assets	**$ (37)**	$ 94	$ (44)	**$ 5**	$ (41)	$ (6)

Significant assumptions used in determining net periodic benefit cost:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2023**	2022	2021	**2023**	2022	2021
Discount rate	**5.69 %**	3.06 %	2.73 %	**5.70 %**	3.11 %	2.80 %
Expected return on plan assets	**7.00 %**	7.00 %	7.00 %	**n/a**	n/a	n/a
Rate of compensation increase	**3.93 %**	3.71 %	4.52 %	**n/a**	n/a	n/a
Crediting interest rate for cash balance plans	**4.44 %**	1.81 %	1.93 %	**n/a**	n/a	n/a
Health care cost trend rate				**7.00 %**	6.25 %	6.25 %
Ultimate health care cost trend rate				**5.00 %**	5.00 %	5.00 %
Year achieved				**2030**	2026-2027	2025-2026

Participation in Dominion Energy Defined Benefit Plans

Effective January 2021, eligible DESC employees hired after 2013 began accruing benefits under a cash balance formula within the Dominion Energy Pension Plan, a qualified defined benefit pension plan sponsored by Dominion Energy. In addition, DESC employees hired in 2021 prior to July 2021 are covered by the Dominion Energy Pension Plan. As a participating employer, DESC is subject to Dominion Energy's funding policy, which is to contribute annually an amount that is in accordance with ERISA. DESC made no contributions to the Dominion Energy Pension Plan during 2023. DESC made contributions of less than $1 million to the Dominion Energy Pension Plan during 2022. DESC made no contributions to the Dominion Energy Pension Plan during 2021. DESC's net periodic pension cost related to this plan was $2 million, $1 million, and $3 million in 2023, 2022, and 2021, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in DESC's Consolidated Statements of Income. The funded status of various
Dominion Energy subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion Energy subsidiaries. During 2023 and 2022, DESC's pension and other postretirement benefits obligation includes $6 million and $4 million, respectively, for amounts due to Dominion Energy related to this plan.

Dominion Energy holds investments in trusts to fund employee benefit payments for the pension plan in which DESC's employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that DESC will provide to Dominion Energy for its share of employee benefit plan contributions.

401(k) Retirement Savings Plan

Effective January 2021, DESC participates in a defined contribution savings plan sponsored by Dominion Energy. Previously, DESC had participated in a defined contribution plan sponsored by SCANA, which was merged into the Dominion Energy plan in December 2020. DESC recognized employer matching contributions of $14 million, $13 million, and $11 million in 2023, 2022, and 2021, respectively.

12. COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the ordinary course of business, DESC is involved in legal proceedings before various courts and is periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that it is not possible for DESC to estimate a range of possible loss. For such matters that DESC cannot estimate, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that DESC is able to estimate a range of possible loss. For legal proceedings and governmental examinations that DESC is able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. DESC maintains various insurance programs, including general liability insurance coverage which provides coverage for personal injury or wrongful death cases. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent DESC's maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on DESC's financial position, liquidity or results of operations.

Environmental Matters

DESC is subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

From a regulatory perspective, DESC continually monitors and evaluates its current and projected emission levels and strives to comply with all state and federal regulations regarding those emissions. DESC participates in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at its coal-fired electric generating plants. These actions are expected to address many of the rules and regulations discussed herein.

Air

The CAA, as amended, is a comprehensive program utilizing a broad range of regulatory tools to protect and preserve the nation's air quality. At a minimum, states are required to establish regulatory programs to meet applicable requirements of the CAA. However, states may choose to develop regulatory programs that are more restrictive. Many of DESC's facilities are subject to the CAA's permitting and other requirements.

ACE Rule

In July 2019, the EPA published the final rule informally referred to as the ACE Rule, as a replacement for the Clean Power Plan. The ACE Rule regulated GHG emissions from existing coal-fired power plants pursuant to Section 111(d) of the CAA and required states to develop plans by July 2022 establishing unit-specific performance standards for existing coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE Rule and remanded it to the EPA. This decision would take effect upon issuance of the court's mandate. In March 2021, the court issued a partial mandate vacating and remanding all parts of the ACE Rule except for the portion of the ACE Rule that repealed the Clean Power Plan. In October 2021, the U.S. Supreme Court agreed to hear a challenge of the U.S. Court of Appeals for the D.C. Circuit's decision on the ACE Rule. In June 2022, the U.S. Supreme Court reversed the D.C. Circuit's decision on the ACE Rule and remanded the case back to the D.C. Circuit. In May 2023, the EPA proposed to repeal the ACE Rule as part of a package of proposed rules addressing CO_2 emissions from new and existing fossil fuel-fired electric generating units. Until the EPA takes final action on this proposed rulemaking, DESC cannot predict an impact to its operations, financial condition and/or cash flows.

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a PSD or Title V permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and exceed a significant emissions rate of 75,000 tons per year of CO_2 equivalent emissions. Until the EPA ultimately takes final action on this rulemaking, DESC cannot predict the impact to its results of operations, financial condition and/or cash flows.

In December 2018, the EPA proposed revised Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources. The proposed rule would amend the previous determination that the best system of emission reduction for newly constructed coal-fired steam generating units is no longer partial carbon capture and storage. Instead, the proposed revised best system of emission reduction for this source category is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with best operating practices. The proposed revision to the performance standards for coal-fired steam generating units remains pending. Until the EPA ultimately takes final action on this rulemaking, DESC cannot predict the impact to its results of operations, financial condition and/or cash flows.

Water

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. DESC must comply with applicable aspects of the CWA programs at its operating facilities.

Regulation 316(b)

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. DESC has four facilities that are subject to the final regulations. DESC is also working with the EPA and state regulatory agencies to assess the applicability of Section 316(b) to five hydroelectric facilities. DESC anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. DESC is currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technological, and cost benefit studies. DESC is conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications at certain facilities to ensure compliance with this rule. While the impacts of this rule could be material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Effluent Limitations Guidelines

In September 2015, the EPA released a final rule to revise the ELG Rule. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the final ELG Rule and stayed future compliance dates in the rule. Also in April 2017, the U.S. Court of Appeals for the Fifth Circuit granted the EPA's request for a stay of the pending consolidated litigation challenging the rule while the EPA addresses the petitions for reconsideration. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the final ELG Rule from November 2018 to November 2020; however, the latest date for compliance for these regulations was December 2023. In October 2020, the EPA released the final rule that extends the latest dates for compliance. Individual facilities' compliance dates will vary based on circumstances and the determination by state regulators and may range from 2021 to 2028. While the impacts of this rule could be material to DESC's results of operations, financial condition and/or cash flows, as DESC expects that wastewater treatment technology retrofits and modifications at the Wateree generating station will be required, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Capacity Use Area

In November 2019, a new CUA was established in the counties surrounding the Cope Generating Station (Western Capacity Use Area) under the South Carolina Groundwater Use and Reporting Regulation. Under the regulation any groundwater well in a CUA that withdraws above three million gallons per month must be permitted. The Cope Generating Station is located within this new Western Capacity Use Area. Cope has been using four deep groundwater wells for cooling water and other house loads since 1996. Prior to designation of the new Western Capacity Use Area, the wells at Cope Station were only required to be registered not permitted. As a result of this designation, Cope will need to restore the surface water equipment to operable status to reduce reliance on groundwater wells. This includes completion of 316(b) requirements, (including SCDHEC BACT determination and modification of the station national pollutant discharge elimination system permit) and extensive inspection, repair and/or replacement of the associated surface water withdrawal equipment which has been idle since 1996. While the impacts of this rule change are potentially material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Waste Management and Remediation

The operations of DESC are subject to a variety of state and federal laws and regulations governing the management and disposal of solid and hazardous waste, and release of hazardous substances associated with current and/or historical operations. The CERCLA, as amended, and similar state laws, may impose joint, several and strict liability for cleanup on potentially responsible parties who owned, operated or arranged for disposal at facilities affected by a release of hazardous substances. In addition, many states have created programs to incentivize voluntary remediation of sites where historical releases of hazardous substances are identified and property owners or responsible parties decide to initiate cleanups.

From time to time, DESC may be identified as a potentially responsible party in connection with the alleged release of hazardous substances or wastes at a site. Under applicable federal and state laws, DESC could be responsible for costs associated with the investigation or remediation of impacted sites, or subject to contribution claims by other responsible parties for their costs incurred at such sites. DESC also may identify, evaluate and remediate other potentially impacted sites under voluntary state programs. Remediation costs may be subject to reimbursement under DESC's insurance policies, rate recovery mechanisms, or both. Except as described below, DESC does not believe these matters will have a material effect on results of operations, financial condition and/or cash flows.

DESC has four decommissioned manufactured gas plant sites in South Carolina that are in various states of investigation, remediation and monitoring under work plans approved by, or under review by, the SCDHEC or the EPA. In the fourth quarter of 2023, DESC completed the majority of remediation activities at one site. DESC anticipates the remaining activities at that site will be completed by 2025 at an estimated cost of $6 million, after which the site will continue to incur ongoing maintenance and monitoring obligations. DESC expects to recover costs arising from the remediation work at all four sites through rate recovery mechanisms and as of December 31, 2023, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $35 million and are included in regulatory assets.

Ash Pond and Landfill Closure Costs

In April 2015, the EPA enacted a final rule regulating CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store, CCRs. DESC currently has inactive and existing CCR ponds and CCR landfills subject to the final rule at two different facilities. This rule created a legal obligation for DESC to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary.

In December 2016, legislation was enacted that creates a framework for EPA- approved state CCR permit programs. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. In September 2017, the EPA agreed to reconsider portions of the CCR rule in response to two petitions for reconsideration. In March 2018, the EPA proposed certain changes to the CCR rule related to issues remanded as part of the pending litigation and other issues the EPA is reconsidering. Several of the proposed changes would allow states with approved CCR permit programs additional flexibility in implementing their programs. In July 2018, the EPA promulgated the first phase of changes to the CCR rule. In August 2018, the U.S. Court of Appeals for the D.C. Circuit issued its decision in the pending challenges of the CCR rule, vacating and remanding to the EPA three provisions of the rule. Until this matter is resolved and all phases of the CCR rule are promulgated, DESC is unable to precisely estimate potential incremental impacts or costs related to existing coal ash sites in connection with future implementation of the final CCR rule. In May 2023, the EPA released a proposed rule addressing one of the previously remanded provisions of the CCR rule to regulate inactive surface impoundments located at retired generating stations that contained CCR and liquids after October 2015, and certain other inactive or previously closed surface impoundments, landfills or other areas that contain accumulations of CCR. Until the EPA ultimately takes final action on this rulemaking, DESC is unable to predict whether or to what extent the new rules will ultimately require additional controls. While such amounts may be material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts.

Claims and Litigation

The following describes certain legal proceedings involving DESC relating primarily to events occurring before closing of the SCANA Combination. No reference to, or disclosure of, any proceeding, item or matter described below shall be construed as an admission or indication that such proceeding, item or matter is material. For certain of these matters, and unless otherwise noted therein, DESC is unable to estimate a reasonable range of possible loss and the related financial statement impacts, but for any such matter there could be a material impact to its results of operations, financial condition and/or cash flows. For the matters for which DESC is able to reasonably estimate a probable loss, the Consolidated Balance Sheets at December 31, 2022 include reserves of $94 million, and insurance receivables of $68 million, included within other receivables. The balance at December 31, 2022 includes $68 million of offsetting reserves and insurance receivables related to personal injury or wrongful death cases which were pending. The Consolidated Balance Sheets at December 31, 2023 included an inconsequential amount of reserves primarily related to personal injury or wrongful death cases. For the years ended December 31, 2023 and 2022, charges included in DESC's Consolidated Statements of Comprehensive Income were inconsequential. DESC's Consolidated Statements of Comprehensive Income for the year ended December 31, 2021 includes charges of $70 million ($53 million after-tax), within impairment of assets and other charges, reflected in the Corporate and Other segment.

Governmental Proceedings and Investigations

In June 2018, DESC received a notice of proposed assessment of approximately $410 million, excluding interest, from the SCDOR following its audit of DESC's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. The proposed assessment, which includes 100% of the NND Project, is based on the SCDOR's position that DESC's sales and use tax exemption for the NND Project does not apply because the facility will not become operational. In December 2020, the parties reached an agreement in principle in the amount of $165 million to resolve this matter. In June 2021, the parties executed a settlement agreement which allows DESC to fund the settlement amount through a combination of cash, shares of Dominion Energy common stock or real estate with an initial payment of at least $43 million in shares of Dominion Energy common stock. In August 2021, Dominion Energy issued 0.6 million shares of its common stock to satisfy DESC's obligation for the initial payment under the settlement agreement. In May 2022, Dominion Energy issued an additional 0.9 million shares of its common stock to partially satisfy DESC's remaining obligation under the settlement agreement. In June 2022, DESC requested approval from the South Carolina Commission to transfer certain real estate with a total settlement value of $51 million to satisfy its remaining obligation under the settlement agreement. In July 2022, the South Carolina Commission voted to approve the request and issued its final order in August 2022. In September 2022, DESC transferred certain non-utility property with a fair value of $28 million to the SCDOR under the settlement agreement, resulting in a gain of $19 million ($14 million after-tax) recorded in other income (expense), net in DESC's Consolidated Statements of Comprehensive Income for the year ended December 31, 2022. In December 2022, DESC transferred additional utility property with a fair value of $3 million to the SCDOR, resulting in an inconsequential gain. In October 2022, DESC filed for approval to transfer the remaining real estate with FERC which was received in November 2022. In March 2023, DESC transferred utility property with a fair value of $10 million to the SCDOR resulting in a gain of $9 million ($7 million after-tax), recorded in other income (expense), net (reflected in the Corporate and Other segment) in DESC's Consolidated Statements of Comprehensive Income for the year ended December 31, 2023. In June 2023, DESC transferred the remaining utility property with a fair value of $11 million to the SCDOR resulting in a gain of $11 million ($8 million after-tax), recorded in other income (expense), net (reflected in the Corporate and Other segment) in DESC's Consolidated Statements of Comprehensive Income for the year ended December 31, 2023. In July 2023, DESC made a less than $1 million cash payment to the SCDOR to fully satisfy its remaining obligation, including applicable interest, under the settlement agreement.

<u>Matters Fully Resolved Prior to 2023 Impacting the Consolidated Financial Statements</u>

Ratepayer Class Actions

In May 2018, a consolidated complaint against DESC, SCANA and the State of South Carolina was filed in the State Court of Common Pleas in Hampton County, South Carolina (the DESC Ratepayer Case). The plaintiffs alleged, among other things, that DESC was negligent and unjustly enriched, breached alleged fiduciary and contractual duties and committed fraud and misrepresentation in failing to properly manage the NND Project, and that DESC committed unfair trade practices and violated state anti-trust laws. In December 2018, the State Court of Common Pleas in Hampton County entered an order granting preliminary approval of a class action settlement. The court entered an order granting final approval of the settlement in June 2019, which became effective in July 2019. The settlement agreement, contingent upon the closing of the SCANA Combination, provided that SCANA and DESC establish an escrow account and proceeds from the escrow account would be distributed to the plaintiffs, after payment of certain taxes, attorneys' fees and other expenses and administrative costs. The escrow account would include (1) up to $2.0 billion, net of a credit of up to $2.0 billion in future electric bill relief, which would inure to the benefit of the escrow account in favor of class members over a period of time established by the South Carolina Commission in its order related to matters before the South Carolina Commission related to the NND Project, (2) a cash payment of $115 million and (3) the transfer of certain DESC-owned real estate or sales proceeds from the sale of such properties, which counsel for the plaintiffs estimated to have an aggregate value between $60 million and $85 million. At the closing of the SCANA Combination, SCANA and DESC funded the cash payment portion of the escrow account. In July 2019, DESC transferred $117 million representing the cash payment, plus accrued interest, to the plaintiffs. Through August 2020, property, plant and equipment with a net recorded value of $22 million had been transferred to the plaintiffs in coordination with the court-appointed real estate trustee to satisfy the settlement agreement. In September 2020, the court entered an order approving a final resolution of the transfer of real estate or sales proceeds with a cash contribution of $38.5 million by DESC and the conveyance of property, plant and equipment with a net recorded value of $3 million, which was completed by DESC in October 2020. In December 2021, the court approved a motion for and DESC completed the repurchase of $8 million of property, plant and equipment previously transferred to the plaintiffs.

SCANA Shareholder Litigation

In February 2018, a purported class action was filed against Dominion Energy and certain former directors of SCANA and DESC in the State Court of Common Pleas in Richland County, South Carolina (the Metzler Lawsuit). The plaintiff alleges, among other things, that defendants violated their fiduciary duties to shareholders by executing a merger agreement that would unfairly deprive plaintiffs of the true value of their SCANA stock, and that Dominion Energy aided and abetted these actions. Among other remedies, the plaintiff seeks to enjoin and/or rescind the merger. In February 2018, Dominion Energy removed the case to the U.S. District Court for the District of South Carolina and filed a Motion to Dismiss in March 2018. In September 2019, the U.S. District Court for the District of South Carolina granted the plaintiffs' motion to consolidate the Metzler Lawsuit with another lawsuit regarding the SCANA Merger Agreement to which DESC is not a party. In October 2019, the plaintiffs filed an amended complaint against certain former directors and executive officers of SCANA and DESC, which stated substantially similar allegations to those in the initial lawsuits as well as an inseparable fraud claim. In November 2019, the defendants filed a motion to dismiss. In April 2020, the U.S. District Court for the District of South Carolina denied the motion to dismiss. In May 2020, SCANA filed a motion to intervene, which was denied in August 2020. In September 2020, SCANA filed a notice of appeal with the U.S. Court of Appeals for the Fourth Circuit. In June 2021, the parties reached an agreement in principle to settle this case, along with a related case to which DESC was not a party, subject to court approval, with no financial impact to DESC. In June 2022, this case was dismissed in connection with court approval of the related case to which DESC was not a party.

FILOT Litigation and Related Matters

In November 2017, Fairfield County filed a complaint and a motion for temporary injunction against DESC in the State Court of Common Pleas in Fairfield County, South Carolina, making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of implied duty of good faith and fair dealing and unfair trade practices related to DESC's termination of the FILOT agreement between DESC and Fairfield County related to the NND Project. The plaintiff sought a temporary and permanent injunction to
prevent DESC from terminating the FILOT agreement. The plaintiff withdrew the motion for temporary injunction in December 2017. In July 2021, the parties executed a settlement agreement requiring DESC to pay $99 million, which could be satisfied in either cash or shares of Dominion Energy common stock. Also in July 2021, the State Court of Common Pleas in Fairfield County, South Carolina approved the settlement. In July 2021, Dominion Energy issued 1.4 million shares of Dominion Energy common stock to satisfy DESC's obligation under the settlement agreement.

Nuclear Insurance

Under Price-Anderson, DESC (for itself and on behalf of Santee-Cooper) maintains agreements of indemnity with the U.S. Nuclear Regulatory Commission that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Summer. Price-Anderson provides funds up to $16.2 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by American Nuclear Insurers with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is liable for up to $166 million per reactor owned for each nuclear incident occurring at any reactor in the U.S., provided that not more than $25 million of the liability per reactor would be assessed per year. DESC's maximum assessment, based on its two-thirds ownership of Summer, would be $111 million per incident, but not more than $15 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

DESC currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer for property damage and outage costs up to $1.06 billion resulting from an event of nuclear origin and up to $1 million resulting from an event of a non-nuclear origin. The NEIL policies in aggregate, are subject to a maximum loss of $1.06 billion for any single loss occurrence. The NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, DESC's portion of the retrospective premium assessment would not exceed $12 million. DESC currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Summer for property damage and outage costs up to $1 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, DESC's portion of the retrospective premium assessment would not exceed an inconsequential amount.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Summer exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that DESC's rates would not recover the cost of any purchased replacement power, DESC will retain the risk of loss as a self-insurer. DESC has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on DESC's results of operations, cash flows and financial position.

Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. DESC entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. By mutual agreement of the parties, damage award payments and settlement payments are made until the DOE has accepted the same amount of spent fuel from the facility as if it has fully performed its contractual obligations. In 2023, DESC received payment of $6 million for resolution of its share of claims incurred at Summer for the period of January 1, 2022 through December 31, 2022. In 2022, DESC received payment of $1 million for resolution of its share of claims incurred at Summer for the period of January 1, 2021 through December 31, 2021. In 2021, DESC received payment of $1 million for resolution of its share of claims incurred at Summer for the period of January 1, 2020 through December 31, 2020. As of December 31, 2023, the federal government has not accepted any spent fuel from Summer, and it remains unclear when the repository may become available. DESC has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Summer. DESC may evaluate other technology as it becomes available.

Long-Term Purchase Agreements

At December 31, 2023, DESC had the following long-term commitments that are noncancelable or cancelable only under certain conditions, and that a third party that will provide the contracted goods or services has used to secure financing.

(millions)		2024		2025		2026		2027		2028		Thereafter		Total
Purchased electric capacity(1)(2)	$	77	$	77	$	80	$	81	$	81	$	517	$	913

(1) Includes affiliated amounts with certain solar facilities of $185 million.
(2) Commitments represent estimated amounts payable for energy under power purchase contracts with qualifying facilities which expire at various dates through 2040. Energy payments are generally based on fixed dollar amounts per month and totaled $70 million in 2023, $75 million in 2022 and $73 million in 2021.

Surety Bonds
At December 31, 2023, DESC had purchased $24 million of surety bonds. Under the terms of surety bonds, DESC is obligated to indemnify the respective surety bond company for any amounts paid.

13. LEASES

At December 31, 2023 and 2022, DESC had the following lease assets and liabilities recorded in the Consolidated Balance Sheets:

At December 31,		2023		2022
(millions)				
Lease assets:				
Operating lease assets(1)	$	18	$	21
Finance lease assets(2)		6		9
Total lease assets	$	24	$	30
Lease liabilities:				
Operating lease - current(3)	$	2	$	3
Operating lease - noncurrent(4)		17		18
Finance lease - current(5)		3		4
Finance lease - noncurrent		4		6
Total lease liabilities	$	26	$	31

(1)Included in other deferred debits and other assets in the Consolidated Balance Sheets.
(2)Included in utility plant, net, in the Consolidated Balance Sheets, net of $17 million and $20 million of accumulated amortization at December 31, 2023 and December 31, 2022, respectively.
(3)Included in other current liabilities in the Consolidated Balance Sheets.
(4)Included in other deferred credits and other liabilities in the Consolidated Balance Sheets.
(5)Included in securities due within one year in the Consolidated Balance Sheets.

At December 31, 2023 and 2022, DESC had the following lease assets and liabilities recorded in the Consolidated Balance Sheets within the FERC accounts noted:

(millions)		Electric	Gas	Common	Nonutility	Total
December 31, 2023						
Operating Leases						
Account 101.1	Property Under Capital Lease	$8	$—	$—	$—	$8
Account 118	Other Utility Plant	—	—	11	—	11
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(6)	—	(11)	—	(17)
Account 243	Obligations Under Capital Lease - Current	(2)	—	—	—	(2)
Finance Leases						
Account 101.1	Property Under Capital Lease	5	—	—	—	5

Account 118	Other Utility Plant	—	—	—	—	—
Account 121	Nonutility Property	—	—	—	—	—
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 122	Accumulated Provision for Depreciation and Amortization of Nonutility Property	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(3)	—	—	—	(3)
Account 243	Obligations Under Capital Lease - Current	(2)	—	—	—	(2)

(millions)		Electric	Gas	Common	Nonutility	Total
December 31, 2022						
Operating Leases						
Account 101.1	Property Under Capital Lease	$10	$—	$—	$—	$10
Account 118	Other Utility Plant	—	—	11	—	11
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(7)	—	(11)	—	(18)
Account 243	Obligations Under Capital Lease - Current	(3)	—	—	—	(3)
Finance Leases						
Account 101.1	Property Under Capital Lease	8	—	—	—	8
Account 118	Other Utility Plant	—	1	1	—	2
Account 121	Nonutility Property	—	—	—	1	1
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 122	Accumulated Provision for Depreciation and Amortization of Nonutility Property	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(5)	—	(1)	—	(6)
Account 243	Obligations Under Capital Lease - Current	(3)	—	—	(1)	(4)

For the years ended December 31, 2023, 2022 and 2021, total lease cost consisted of the following:

Year Ended December 31,	**2023**	2022	2021
(millions)			
Finance lease cost:			
Amortization	**$ 3**	$ 4	$ 6
Interest	**—**	1	1
Operating lease cost	**5**	4	4
Short-term lease cost	**2**	2	2
Total lease cost	**$ 10**	$ 11	$ 13

For the years ended December 31, 2023, 2022 and 2021, cash paid for amounts included in the measurement of lease liabilities consisted of the following amounts, included in the Consolidated Statements of Cash Flows:

Year Ended December 31,	**2023**	2022	2021
(millions)			
Operating cash flows from finance leases	**$ —**	$ 1	$ 1
Operating cash flows from operating leases	**4**	6	4
Financing cash flows from finance leases	**4**	4	6

At December 31, 2023 and 2022, the weighted average remaining lease term and weighted average discount rate for finance and operating leases were as follows:

At December 31,	**2023**	2022
Weighted average remaining lease term - finance leases	**3 years**	3 years
Weighted average remaining lease term - operating leases	**18 years**	17 years
Weighted average discount rate - finance leases	**2.96 %**	2.91 %
Weighted average discount rate - operating leases	**4.12 %**	3.94 %

Lease liabilities have the following scheduled maturities:

(millions)	**Operating**	**Finance**
2024	**$ 3**	**$ 3**
2025	**2**	**2**
2026	**2**	**1**
2027	**2**	—
2028	**1**	—
After 2028	**19**	—
Total undiscounted lease payments	**29**	**6**
Present value adjustment	**(10)**	**1**
Present value of lease liabilities	**$ 19**	**$ 7**

14. OPERATING SEGMENTS

The Corporate and Other Segment primarily includes specific items attributable to DESC's operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources.

In 2023, DESC reported after-tax net income of $18 million for specific items in the Corporate and Other segment, all of which was attributable to its operating segment.

The net income for specific items attributable to DESC's operating segment in 2023 primarily related to a $28 million ($21 million after-tax) benefit related to real estate transactions, including gains on the transfer of property to satisfy litigation associated with the NND Project.

In 2022, DESC reported after-tax expenses of $3 million for specific items in the Corporate and Other segment, all of which was attributable to its operating segment.

In 2021, DESC reported after-tax net expenses of $212 million for specific items in the Corporate and Other segment, of which $208 million was attributable to its operating segment.

The net expense for specific items attributable to DESC's operating segment in 2021 primarily related to $266 million ($199 million after-tax) of charges associated with the settlement of the South Carolina electric base rate case and a $70 million ($53 million after-tax) charge associated with litigation.

The following table presents segment information pertaining to DESC's operations:

Year Ended December 31,	Dominion Energy South Carolina	Corporate and Other	Consolidated Total
(millions)			
2023			
External revenue	**$ 3,028**	**$ —**	**$ 3,028**
Depreciation and amortization	**510**	**—**	**510**
Interest charges, net of AFUDC	**240**	**—**	**240**
Income tax expense (benefit)	**80**	**—**	**80**
Comprehensive income (loss) available (attributable) to common shareholder	**357**	**18**	**375**
Capital expenditures	**900**	**—**	**900**
Total assets (billions)	**15.2**	**—**	**15.2**
2022			
External revenue	$ 3,783	$ —	$ 3,783
Depreciation and amortization	486	—	486
Interest charges, net of AFUDC	213	—	213
Income tax expense (benefit)	126	(1)	125
Comprehensive income (loss) available (attributable) to common shareholder	485	(3)	482
Capital expenditures	675	—	675
Total assets (billions)	15.1	—	15.1
2021			
External revenue	$ 3,146	$ —	$ 3,146
Depreciation and amortization	466	—	466
Interest charges, net of AFUDC	206	(23)	183
Income tax expense (benefit)	124	(116)	8
Comprehensive income (loss) available (attributable) to common shareholder	421	(212)	209
Capital expenditures	736	—	736
Total assets (billions)	14.3	—	14.3

15. UTILITY PLANT AND NONUTILITY PROPERTY

Major classes of utility plant and other property and their respective balances at December 31, 2023 and 2022 were as follows:

At December 31,	2023	2022
(millions)		
Gross utility plant:		
Generation	**$ 5,509**	$ 5,327
Transmission	**2,272**	2,145
Distribution	**5,901**	5,472
Storage	**79**	76
General and other	**644**	617
Intangible	**295**	270
Construction work in progress	**551**	515
Nuclear fuel	**609**	550
Total gross utility plant	**$ 15,860**	$ 14,972
Gross nonutility property	**$ 25**	$ 21

Jointly Owned Utility Plant

DESC jointly owns and is the operator of Summer. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership. DESC's share of the direct expenses of Summer is included in the corresponding operating expenses on its income statement. The units associated with the NND Project, net of impairment charges, have been reclassified from construction work in progress to a regulatory asset as a result of the decision to stop their construction. See additional discussion at Note 3.

At December 31,	2023	2022
	Summer Unit 1	Summer Unit 1
Percent owned	**66.7%**	66.7%
Plant in service	**$ 1.6 billion**	$ 1.6 billion
Accumulated depreciation	**$ 772 million**	$ 751 million
Construction work in progress	**$ 88 million**	$ 87 million

Included within other receivables on the balance sheet were amounts due to DESC from Santee Cooper for its share of direct expenses. These amounts totaled $50 million at December 31, 2023 and $21 million at December 31, 2022.

16. AFFILIATED AND RELATED PARTY TRANSACTIONS

DES, on behalf of itself and its parent company, provides the following services to DESC, which are rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative and retirement benefits. Costs for these services include amounts capitalized. Amounts expensed are primarily recorded in other operations and maintenance - affiliated suppliers and other income, net in the Consolidated Statements of Comprehensive Income.

DESC transacts with affiliates for certain quantities of electricity in the ordinary course of business. DESC also enters into certain commodity derivative contracts with affiliates. DESC uses these contracts, which are principally comprised of forward commodity purchases, to manage commodity price risks associated with purchases of electricity. See Note 8 for more information.

Year Ended December 31,	2023	2022	2021
(millions)			
Direct and allocated costs from DES and DESS[1]	**227**	210	230
Operating Revenues – Electric from sales to affiliate	**4**	4	4
Operating Revenues – Gas from sales to affiliate	**1**	1	1
Operating Expenses – Other taxes from affiliate	**8**	8	7

Purchases of electricity from solar affiliates	**13**	14	14
Purchases of electric generation from affiliate	**186**	153	160

(1)Includes capitalized expenditures of $33 million, $38 million and $30 million for the years ended December 31, 2022, 2021 and 2020, respectively.

At December 31,	**2023**	2022
(millions)		
Payable to DES	**17**	22
Payable to SCANA	**7**	7
Payable to Public Service Company of North Carolina, Incorporated	**13**	12
Payable to DEI	**—**	1
Payable to GENCO	**16**	18
Derivative assets with affiliates(1)	**33**	51

(1)Includes amounts recorded in other current assets of $2 million and $8 million as of December 31, 2023 and 2022, respectively, and amounts recorded in other deferred debits and other assets of $31 million and $43 million as of December 31, 2023 and 2022, respectively.

Certain disclosures regarding tax related affiliate balances are included in Note 2. Borrowings from an affiliate are described in Note 6. Certain disclosures regarding DESC's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are included in Note 11.

17. OTHER INCOME (EXPENSE), NET

Components of other income (expense), net are as follows:

Year Ended December 31,	**2023**	2022	2021
(millions)			
Other income	**8**	10	11
Gain on sales of assets (1)	**32**	42	—
Other expense	**(16)**	2	(18)
Allowance for equity funds used during construction	**—**	—	4
Other expense, net	**$ 24**	$ 54	$ (3)

(1)Includes amounts recognized in connection with the transfer of property, plant and equipment to satisfy litigation. See Note 12 for additional information.

Non-service cost components of pension and other postretirement benefits are included in other expense.

In 2023, DESC completed the sale of certain utility property in South Carolina, as approved by the South Carolina Commission in February 2023, for total cash consideration of $12 million. In connection with the sale, DESC recognized a net gain of $11 million ($8 million after-tax), reflected in the Corporate and Other segment, for the year ended December 31, 2023.

In 2022, DESC completed the sales of certain utility property in South Carolina, as approved by the South Carolina Commission, for total cash consideration of $20 million. In connection with the sales, DESC recognized a gain of $20 million ($15 million after-tax) for the year ended December 31, 2022.

18. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $169 million and $188 million in 2023 and 2022, respectively.

Net income taxes paid (received): $67 million and ($132 million) in 2023 and 2022, respectively.

Noncash Investing and Financing Activities:

Accrued construction expenditures: $92 million and $122 million at December 31, 2023 and 2022, respectively.

See Note 5 for noncash financing activities related to capital contributions associated with the settlement of litigation.
See Note 12 for noncash investing activities related to the property, plant and equipment conveyed to satisfy litigation.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				[a](582,602)			[g](582,602)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[b]12,755			12,755		
3	Preceding Quarter/Year to Date Changes in Fair Value				[c](947,333)			(947,333)		
4	Total (lines 2 and 3)				(934,578)			(934,578)	482,587,046	481,652,468
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,517,180)			(1,517,180)		
6	Balance of Account 219 at Beginning of Current Year				(1,517,180)			(1,517,180)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[d]92,296			92,296		
8	Current Quarter/Year to Date Changes in Fair Value				[e]284,455			284,455		
9	Total (lines 7 and 8)				376,751			376,751	374,554,944	374,931,695
10	Balance of Account 219 at End of Current Quarter/Year				[f](1,140,429)			(1,140,429)		

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

Lines 1-5 present information for the period 1/1/22 - 12/31/22.
Lines 6-10 present information for the period 1/1/23 - 12/31/23.

(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Reflects reclassification adjustments of amounts recognized in AOCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit costs in 2022.

(c) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossChangesInFairValue

Amount reflects adjustment to AOCI, and reclassification to expense, for changes in fair value of employee benefit plan obligations. Amount reflects amounts recognized in AOCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service costs arising during 2022 (as applicable).

(d) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Reflects reclassification adjustments of amounts recognized in AOCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit costs in 2023

(e) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossChangesInFairValue

Amount reflects adjustment to AOCI, and reclassification to expense, for changes in fair value of employee benefit plan obligations. Also reflects amounts recognized in AOCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service costs arising during 2023 (as applicable)

(f) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

Other Comprehensive Income related to deferred employee benefit plan costs

(g) Concept: AccumulatedOtherComprehensiveIncomeLoss

Lines 1-5 present information for the period 1/1/22 - 12/31/22.
Lines 6-10 present information for the period 1/1/23 - 12/31/23.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	13,668,234,397	11,605,308,643	1,708,141,058				354,784,696
4	Property Under Capital Leases	25,227,316	13,260,638	428,111				11,538,567
5	Plant Purchased or Sold							
6	Completed Construction not Classified	969,202,177	781,418,058	135,390,657				52,393,462
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	14,662,663,890	12,399,987,339	1,843,959,826				418,716,725
9	Leased to Others							
10	Held for Future Use	9,185,111	9,185,111					
11	Construction Work in Progress	569,573,518	507,175,416	47,961,595				14,436,507
12	Acquisition Adjustments	31,597,076	31,360,826	236,250				
13	Total Utility Plant (8 thru 12)	15,273,019,595	12,947,708,692	1,892,157,671				433,153,232
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,869,410,815	5,069,626,532	597,085,507				202,698,776
15	Net Utility Plant (13 less 14)	9,403,608,780	7,878,082,160	1,295,072,164				230,454,456
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	5,634,634,215	4,975,365,643	581,098,293				78,170,279
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	221,907,015	81,548,804	15,829,714				124,528,497
22	Total in Service (18 thru 21)	5,856,541,230	5,056,914,447	596,928,007				202,698,776
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							
27	Held for Future Use							

28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	12,869,585	12,712,085	157,500				
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,869,410,815	5,069,626,532	597,085,507				202,698,776

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	6,675,649	3,350,754		[(b)]10,026,403	0
3	Nuclear Materials	40,805,957			[(c)]40,805,957	0
4	Allowance for Funds Used during Construction	612,640	1,284,450		[(d)]1,897,090	0
5	(Other Overhead Construction Costs, provide details in footnote)	469,861	[(a)]861,037		[(e)]1,019,464	311,434
6	SUBTOTAL (Total 2 thru 5)	48,564,107	5,496,241		53,748,914	311,434
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	120,440,247	53,140,500			173,580,747
9	In Reactor (120.3)	165,107,401			[(f)]21,672,113	143,435,288
10	SUBTOTAL (Total 8 & 9)	285,547,648	53,140,500		21,672,113	317,016,035
11	Spent Nuclear Fuel (120.4)	216,049,432	75,421,027			291,470,459
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	346,659,275		(33,087,217)		379,746,492
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	203,501,912	134,057,768	33,087,217	75,421,027	229,051,436
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationAdditions

Additions for Other Overhead Construction Costs includes Fuel labor-related expenses of $393,368 and Software License expenses of $467,669.

(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer fuel invoices/balances from Batch 30 In-Process to Batch 30 - In reactor.

(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer fuel invoices/balances from Batch 30 In-Process to Batch 30 - In reactor.

(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer fuel invoices/balances from Batch 30 In-Process to Batch 30 - In reactor

(e) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer fuel invoices/balances from Batch 30 In-Process to Batch 30 - In reactor

(f) Concept: NuclearFuelAssembliesInReactorOtherReductions

Transfer fuel invoices/balances from Batch 30 In-Process to Batch 30 - In reactor and Transfer Batch 27 In-Reactor to Batch 27 - Spent Fuel

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	7,287,665					7,287,665
3	(302) Franchise and Consents	13,156,558	10,276,184				23,432,742
4	(303) Miscellaneous Intangible Plant	85,444,072	7,299,011	2,368,713			90,374,370
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	105,888,295	17,575,195	2,368,713			121,094,777
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	13,478,704					13,478,704
9	(311) Structures and Improvements	272,146,841	14,358,370	272,518			286,232,693
10	(312) Boiler Plant Equipment	1,225,060,838	24,773,575	9,864,308			1,239,970,105
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	528,521,570	24,262,809	3,498,602			549,285,777
13	(315) Accessory Electric Equipment	99,253,154	563,740	693,120			99,123,774
14	(316) Misc. Power Plant Equipment	49,005,611	6,695,522	3,023,908			[(a)] 52,677,225
15	(317) Asset Retirement Costs for Steam Production	4,525,638	99,699,191	49,903,332			54,321,497
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,191,992,356	170,353,207	67,255,788			2,295,089,775
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	880,612					880,612
19	(321) Structures and Improvements	392,094,132	1,516,201	204,364			[(b)] 393,405,969
20	(322) Reactor Plant Equipment	562,799,142	16,164,045	4,070,489			574,892,698
21	(323) Turbogenerator Units	110,774,419	47,372	571,095			110,250,696
22	(324) Accessory Electric Equipment	119,532,286	3,885,611	293,941			123,123,956
23	(325) Misc. Power Plant Equipment	217,330,185	11,372,438	1,915,192			226,787,431
24	(326) Asset Retirement Costs for Nuclear Production	62,564,231					62,564,231

25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,465,975,007	32,985,667	7,055,081			1,491,905,593
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	29,558,225	850	5,799		1,897	29,555,173
28	(331) Structures and Improvements	52,349,429	1,347,956	100,151		2,645	53,599,879
29	(332) Reservoirs, Dams, and Waterways	455,632,584	4,055,210	1,012			459,686,782
30	(333) Water Wheels, Turbines, and Generators	95,963,218	5,127,968	432,674			100,658,512
31	(334) Accessory Electric Equipment	36,080,416	(101,714)	225,248			35,753,454
32	(335) Misc. Power Plant Equipment	13,576,242	1,905,226	53,625			15,427,843
33	(336) Roads, Railroads, and Bridges	1,817,517					1,817,517
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	684,977,631	12,335,496	818,509		4,542	696,499,160
36	D. Other Production Plant						
37	(340) Land and Land Rights	2,917,435				(5,261)	2,912,174
38	(341) Structures and Improvements	48,409,709	6,002,066	879,770			53,532,005
39	(342) Fuel Holders, Products, and Accessories	12,596,812	6,046	564,825			12,038,033
40	(343) Prime Movers	656,378,863	18,755,452	6,226,800			668,907,515
41	(344) Generators	192,591,463	10,835,504	3,448,942			199,978,025
42	(345) Accessory Electric Equipment	67,592,906	13,553,613	1,727,608			79,418,911
43	(346) Misc. Power Plant Equipment	4,235,990	1,436,584	270,650			5,401,924
44	(347) Asset Retirement Costs for Other Production	(5,810,719)	(12,164,493)				(17,975,212)
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	978,912,459	38,424,772	13,118,595		(5,261)	1,004,213,375
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,321,857,453	254,099,142	88,247,973		(719)	5,487,707,903
47	3. Transmission Plant						
48	(350) Land and Land Rights	121,124,443	291,441	313,749		869,213	[c] 121,971,348
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	7,193,809				(18,453)	7,175,356
50	(353) Station Equipment	687,946,606	19,772,685	660,407		(3,933,312)	703,125,572
51	(354) Towers and Fixtures	3,960,446					3,960,446
52	(355) Poles and Fixtures	846,872,606	83,363,285	4,062,698			926,173,193
53	(356) Overhead Conductors and Devices	396,618,682	33,997,617	2,017,004			428,599,295
54	(357) Underground Conduit	19,549,115					19,549,115
55	(358) Underground Conductors and Devices	57,699,638					57,699,638
56	(359) Roads and Trails	73,767					73,767
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,141,039,112	137,425,028	7,053,858		(3,082,552)	[d] 2,268,327,730

59	4. Distribution Plant						
60	(360) Land and Land Rights	69,049,888	4,208,151	7,332		156,032	73,406,739
61	(361) Structures and Improvements	3,017,301				(333,989)	2,683,312
62	(362) Station Equipment	482,678,719	32,001,066	1,560,712		3,933,312	517,052,385
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	542,743,804	27,394,954	3,872,555			566,266,203
65	(365) Overhead Conductors and Devices	608,805,498	33,600,718	2,737,114			639,669,102
66	(366) Underground Conduit	185,648,724	14,480,022	84,732			200,044,014
67	(367) Underground Conductors and Devices	554,579,870	40,335,111	1,498,038			593,416,943
68	(368) Line Transformers	576,482,337	41,841,024	796,971			617,526,390
69	(369) Services	327,000,755	23,437,765	180,738			350,257,782
70	(370) Meters	180,019,292	43,448,391	13,046,502			210,421,181
71	(371) Installations on Customer Premises						
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	434,778,844	36,126,627	2,432,196			468,473,275
74	(374) Asset Retirement Costs for Distribution Plant	3,357,090					3,357,090
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,968,162,122	296,873,829	26,216,890		3,755,355	4,242,574,416
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	24,550,275	137,528	10,969		(1,019,984)	23,656,850
87	(390) Structures and Improvements	117,169,663	4,542,473	1,231,079			120,481,057
88	(391) Office Furniture and Equipment	14,173,539	7,087,784	95,869			21,165,454
89	(392) Transportation Equipment	26,740,556	3,171,897	3,687,154			26,225,299
90	(393) Stores Equipment	80,474					80,474
91	(394) Tools, Shop and Garage Equipment	5,194,622	410,252	60,509			5,544,365
92	(395) Laboratory Equipment	6,634,204	231,096	166,943			6,698,357
93	(396) Power Operated Equipment	60,337,816	6,254,666	4,456,394			62,136,088
94	(397) Communication Equipment	6,488,475	4,660,643	152,283			10,996,835
95	(398) Miscellaneous Equipment	2,989,895	1,131,257	159,754		(663,664)	3,297,734

96	SUBTOTAL (Enter Total of lines 86 thru 95)	264,359,519	27,627,596	10,020,954		(1,683,648)	280,282,513
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	264,359,519	27,627,596	10,020,954		(1,683,648)	280,282,513
100	TOTAL (Accounts 101 and 106)	11,801,306,501	733,600,790	133,908,388		(1,011,564)	12,399,987,339
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,801,306,501	733,600,790	133,908,388		(1,011,564)	12,399,987,339

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentSteamProduction

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class		Plant Account	Operating Leases Balance at December 31, 2023
Steam Production	316 -	Misc Power Plant Equipment	$3,929,118
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,360,650

(b) Concept: StructuresAndImprovementNuclearProduction

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class		Plant Account	Operating Leases Balance at December 31, 2023
Steam Production	316 -	Misc Power Plant Equipment	$3,929,118
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,360,650

(c) Concept: LandAndLandRightsTransmissionPlant

Functional Class		Plant Account	Operating Leases Balance at December 31, 2023
Steam	316 -	Misc Power Plant Equipment	$3,929,118
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,360,650

(d) Concept: TransmissionPlant

For the formula rate approved in the FERC proceeding listed on page 106, Total Transmission Plant will exclude $4,360,650 of operating leases in Plant Account 350 – Land and Land Rights .

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1	[(a)] See Footnote					
47	TOTAL					

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: LesseeName

The Company charges a rental fee to Segra for communication tower site ground leases.

Dominion Energy Services, Inc. utilizes certain assets, including both office space and equipment, that are owned by Dominion Energy South Carolina (DESC) and classified as electric, gas and common utility plant on the Company's books. DESC charges Dominion Energy Services, Inc. a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Clements Ferry Sub Site Easement	07/01/2020	[a] 07/01/2027	1,037,100
3	Cainhoy-Clements Ferry 115kv Underground Easement	07/01/2020	[b] 07/01/2027	4,767,750
4	Clements Ferry-Jack Primus 115kv Underground 50' R/W	07/01/2020	[c] 07/01/2027	3,375,000
5				
21	Other Property:			
22	Hardeeville Sub Site Land in Fee			5,261
47	TOTAL			9,185,111

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.
(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.
(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Steam Production	
2	McMeekin Fire Protection System	4,541,110
3	Wateree ELG Bottom Ash Water Treatment	1,321,190
4	Wateree Fire System Design & Piping	1,160,954
5	Urquhart Cooling Water Intake Mod	1,007,561
6	Minor Steam Production	6,351,068
7	Nuclear Production	
8	VCS SLR Application	14,998,637
9	Open Phase Detection System	8,038,351
10	SW Chemical Treatment Equipment	5,941,111
11	Simplex Equipment Replacement	5,844,348
12	Spare Transformer	5,224,703
13	"C" Chiller Replacement	5,160,099
14	DG Exciter Replacement - Bravo	4,129,867
15	Alpha DG Exciter Replacement	3,787,294
16	VCS Transformer Replacement	3,319,143
17	EP RCCA Replacements	2,776,315
18	XTF-1 Transformer Rep.	2,455,246
19	NSMART Security Computer Replacemen	2,251,898
20	Feedwater Isolation Valve Actuators	2,094,534
21	Purchase & Install 4 HIGHSTORM Sys	1,729,997
22	RML0008 Replacement	1,642,206
23	Steam Generator Dispersant Injectio	1,543,103
24	Auxiliary Building Roof	1,261,259
25	Feedwater FAC Piping Replac. R27/28	1,201,477
26	Cathodic Protection System Upgrade	1,181,671
27	Waste Gas Compressor Skid Replc	1,152,194
28	S/R PORV Controls	1,119,204
29	Minor Nuclear Production	10,365,787

30	Hydro Production	
31	Saluda Headgate Replacement	17,154,252
32	Fairfield Pumped Storage 3&4 GSU Transformer	3,600,065
33	Fairfield Pumped Storage 5&6 Generator Rewinds	3,487,879
34	Saluda Hydro Dam Rip Rap	2,792,797
35	Stevens Creek Hydro #4 Generator Stator Rewind	1,586,481
36	Parr Shoals Hydro Debris Log Boom	1,465,940
37	Neal Shoals Hydro Unit 2 Shaft & Bearing	1,183,845
38	Minor Hydro Production	5,048,265
39	Other Production	
40	Bushy Park CT Replacement	101,921,171
41	Parr CT Replacement	86,031,721
42	Urquhart Gas Turbine Rotor Life Extension	5,906,754
43	Urquhart Replacement	5,641,912
44	Columbia Energy Center CT1 Dual Fuel Conversion	2,416,351
45	Minor Other Production	16,527,049
46	Overhead Transmission Lines	
47	Stevens Creek Hooks 115kV/LR Plumb	9,253,149
48	Jasper Okatie 230 kV #2: Construc	8,985,159
49	Eastover - Square D 115 kV: Rebuild	8,663,709
50	Cainhoy-Hamlin 115kV: Rebuild Line	5,841,839
51	Queensboro - Ft. Johnson 115kV	4,484,212
52	Burton-St Helena 115 kV: Rebuild	4,399,493
53	Church Creek Ritter 230kV Replace P	4,138,926
54	Summerville 115kV Loop: Replace Woo	2,688,447
55	Riverport Tap Add Acquire RW	2,674,210
56	Okatie-Bluffton 115kV: Rebuild	2,593,832
57	Square D-Hopkins 115kV: Rebuild	1,957,108
58	Jasper Okatie 230 kV acquire RW	1,549,701
59	Minor Elec Overhead Transmission Lines	10,430,540
60	Minor Elec Underground Transmission Lines	281,165
61	Transmission Substation	
62	End of Life/SPF: Upgrade Relay Phas	4,394,603
63	Okatie 230/115kV: Construct	2,509,303
64	Faber Place Sub: Replace 1 & 2 Swit	2,389,801
65	Summerville: Replace and Spare Auto	1,647,838
66	Williams St: Rpl Sw Hs & Rlys	1,133,379

67	Replce Coit Sub 115kV brkrs w/ 63kA	1,120,706
68	Edenwood Sub:1&2 230-115 Repl Autob	1,036,430
69	Minor Transmission Substation	5,379,838
70	Distribution Substation	
71	Dist Subs: Replace Breakers Phase B	3,854,620
72	Coosawatchie 115-23kv Sub	3,456,957
73	Distribution Sub: Replace Breakers	2,821,449
74	Emory 230kV Dist Sub: New Construct	2,426,918
75	Ridgeville Comm Park 115-23 kV Sub	1,670,312
76	Riverland Terrance Sub Upg Bank to	1,257,029
77	Harbison Sub 115 - 23kV 22.4 MVA	1,044,842
78	Minor Distribution Substation	4,681,248
79	Customer Substation	
80	Minor Customer Substation	2,073,114
81	Overhead Distribution Line	
82	Minor Overhead Distribution Line	12,755,131
83	U/G Distribution Lines	
84	Park/Network Tie	2,151,120
85	Minor U/G Distribution Lines	5,442,475
86	Land and Structures	
87	Savage Road New Builiding	1,415,438
88	Minor Land and Structures	1,582,878
89	Transportation & POE	
90	Minor Transportation & POE	12,210,005
91	Office Furniture and Equipment	
92	Minor Office Furniture and Equipment	558,463
93	Communication Equipment	
94	Minor Communication Equipment	1,074,571
95	Tools & Test Equipment	
96	Minor Tools & Test Equipment	487,510
97	Intangible Plant	
98	Minor Intangible Plant	2,293,139
43	Total	507,175,416

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,776,254,480	4,776,254,480		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	280,712,516	280,712,516		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,796,540	6,796,540		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	1,423,375	[a]1,423,375		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	288,932,431	288,932,431		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(125,823,367)	[b](125,823,367)		
13	Cost of Removal	(22,577,635)	(22,577,635)		
14	Salvage (Credit)	2,931,896	2,931,896		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(145,469,106)	(145,469,106)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	55,647,838	[c]55,647,838		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,975,365,643	4,975,365,643		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,163,001,834	1,163,001,834		
21	Nuclear Production	724,610,048	724,610,048		
22	Hydraulic Production-Conventional	302,000,871	302,000,871		
23	Hydraulic Production-Pumped Storage	83,916,526	83,916,526		
24	Other Production	649,527,007	649,527,007		
25	Transmission	584,831,949	584,831,949		

26	Distribution	1,375,352,548	1,375,352,548		
27	Regional Transmission and Market Operation				
28	General	92,124,860	92,124,860		
29	TOTAL (Enter Total of lines 20 thru 28)	4,975,365,643	4,975,365,643		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Depreciation of Asset Retirement Costs recorded as a regulatory asset.

(b) Concept: BookCostOfRetiredPlant

Retirements per Page 207, Line 100 Column (d)	$	133,908,388
Less: Intangible Plant per Page 205, Line 5 column (d)		(2,368,713)
Less: Capital and Operating Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20, Shown as Plant Retirements		(5,716,308)
Total	$	125,823,367

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

ARC retirements reclassified to Regulatory Assets	49,903,332
Loss on meters retired due to AMI project	3,128,243
Loss on Disposal on Assets	3,338,907
Book Cost of Land Retired	142,106
Gain on Disposal on Vehicles	(479,512)
Transfers and Adjustments	(385,238)
Total	$55,647,838

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	[(a)] Canady's Refined Coal, LLC - Unspecified Investments in Subsidiary Companies				56,276			
2	Louisa Refined Coal, LLC - Unspecified Investments in Subsidiary Companies (2)			5,573			[(c)] 35,236	
3	[(b)] Brandon Shores Coaltech, LLC - Unspecified Investments in Subsidiary Companies (3)				149,094			
42	Total Cost of Account 123.1 $		Total	5,573	[(d)] 205,370		35,236	

FOOTNOTE DATA

(a) Concept: DescriptionOfInvestmentsInSubsidiaryCompanies
The balance of this investment at the beginning of the year was actually a credit of $56,276 which was reclassified on the Company's books to Account No. 234 at 12/31/22. Therefore no beginning balance in Account No. 123.1 is shown in column (d). The $56,276 activity in column (e) represents net income during the year. This $56,276 of activity cleared the balance to $0 on the Company's ledger.
(b) Concept: DescriptionOfInvestmentsInSubsidiaryCompanies
The balance of this investment at the beginning of the year was actually a credit of $149,094 which was reclassified on the Company's books to Account No. 234 at 12/31/22. Therefore no beginning balance in Account No. 123.1 is shown in column (d). The $149,094 activity in column (e) represents net income incurred during the year. This activity cleared the balance to $0 on the Company's ledger..
(c) Concept: InvestmentInSubsidiaryCompanies
Amount includes additional investments made during the year of $29,663.
(d) Concept: EquityInEarningsOfSubsidiaryCompanies
Per the USoA instructions, the Company is using Account 418.1 – Equity in Earnings of Subsidiary Companies to account for its equity method losses or gains related to corporate joint ventures carried in Account 123.1 – Investment in Subsidiary Companies. Since these equity method losses or gains are funded by the Company, there are no undistributed retained earnings related to these investments.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	63,773,029	63,938,400	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	130,629,270	136,727,995	
8	Transmission Plant (Estimated)	9,857,696	11,435,557	
9	Distribution Plant (Estimated)	60,634,025	65,908,346	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,762,486	[a]1,892,469	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	202,883,477	215,964,367	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	266,656,506	279,902,767	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Fleet materials and supplies inventory, and fuel.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	692,868.20	622,919	66,892.00		45,625.00		45,625.00		1,186,250.00		2,037,260.20	622,919
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	[a]6,793.80								[b]45,625.00		52,418.80	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used	1,125.60	799									1,125.60	799
21	Cost of Sales/Transfers:												
22													
23													

24													
25													
26													
27													
28	Total												
29	Balance-End of Year	698,536.40	622,120	66,892.00		45,625.00		45,625.00		1,231,875.00		2,088,553.40	622,120
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	659.50		659.50		659.50		659.50		32,315.50		34,953.50	
37	Add: Withheld by EPA									1,319.00		1,319.00	
38	Deduct: Returned by EPA												
39	Cost of Sales	659.50								659.50		[(c)]1,319.00	
40	Balance-End of Year	0.00		659.50		659.50		659.50		32,975.00		34,953.50	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

FOOTNOTE DATA

(a) Concept: AllowancesIssuedLessWithheldAllowancesNumber

EPA allocated new unit set aside emission allowances related to the CSAPR SO2 Group 2 Program.

(b) Concept: AllowancesIssuedLessWithheldAllowancesNumber

EPA allocated vintage 2053 emission allowances related to the SO2 Acid Rain Program.

(c) Concept: AllowancesWithheldCostOfSalesNumber

Total sales of auction allowance reserves set aside by the EPA.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	51,138.50		7,370.00								58,508.50	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	[(a)]1,649.50										1,649.50	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	2,384.90										2,384.90	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													

24													
25													
26													
27													
28	Total												
29	Balance-End of Year	50,403.10		7,370.00								57,773.10	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

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FOOTNOTE DATA

(a) Concept: AllowancesIssuedLessWithheldAllowancesNumber
EPA allocated new unit set aside emission allowances related to the CSAPR NOx Annual Program.

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
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20	TOTAL					

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22	[a] Unrecovered Nuclear Project Costs	2,768,106,000		407	138,405,300	2,087,613,275
23	[b] Unrecovered Plant related to the retirement of Canadys Unit No. 1.	19,761,879		407	1,607,593	2,078,357
24	[c] Unrecovered Plant related to the retirement of Canadys Unit No. 2 and Unit No. 3.	179,502,263	21,390,289	407	12,270,624	55,773,471
25	[d] Unrecovered Plant associated with early retirement of coal equipment at Urquhart Unit No. 3.	557,755		407	111,551	297,469
26	[e] Unrecovered Plant associated with early retirement of coal equipment at McMeekin Station.	1,427,729		407	285,546	761,455
27	[f] Unrecovered Plant associated with AMR Meters	20,941,960	3,128,243	407	2,666,710	15,157,951
28	[g] Unrecovered Plant associated with Gas Encoder Receiver Transmitters	3,717,182	428,539	407	480,489	2,654,267
29	[h] Unrecovered Plant related to the retirement of the Bushy Park Turbines	2,757,632	1,494,144	407	457,248	2,186,072
30	[i] Unrecovered Plant related to the retirement of the Parr Combustion Turbines	5,899,008	5,899,008	407	306,657	5,592,351
49	TOTAL	3,002,671,408	32,340,223		156,591,718	2,172,114,668

FOOTNOTE DATA

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

FERC Authorization received October 25, 2019 in Docket No. AC19-188-000. Amortization period February 2019 through January 2039 per SCPSC Docket No. 2017-370-E, Order No. 2018-804.

(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received December 2012. (Docket No. 2012-218-E, Order 2012-951) Amortization over approximately 14 years beginning January 2013.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(c) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 2013 (Docket No. 2013-276-E, Order 2013-649). Per this SCPSC Order, annual amortization was established at the level of depreciation expense ($12.3 million per year) that was being recorded for the units before their retirement. In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued on August 16, 2021 in Docket No. 2020-125-E) the SCPSC affirmed the $12.3 million annual amortization.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(d) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an annual amortization of $111,551 (5 years) beginning in September 2021.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(e) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an annual amortization of $285,546 (5 years) beginning in September 2021.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(f) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 6, 2019 (Docket No. 2019-241-EG, Order 2019-622). The SCPSC Order set the amortization expense at the level of depreciation currently approved in DESC's rates until DESC's next general retail electric rate case. In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued on August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an amortization period through December 31, 2028.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(g) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 6, 2019 (Docket No. 2019-241-EG, Order 2019-622) and October 14, 2020 (Docket No. 2020-6-G, Order 2020-701). Amortization per the depreciation study approved in Order 2020-701 establishes an amortization period through December 31, 2028.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(h) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received July 2022 (Docket Nos. 2022-107-E and 2021-93-E, Order No. 2022-517). Per this SCPSC Order, DESC reclassified the net carrying value related to it's two simple cycle combustion turbines located at Bushy Park to unrecovered plant regulatory asset account upon its retirement. Annual amortization was established at the level of depreciation expense ($457,248 per year) that was being recorded for the units at their retirement date of September 2022.

(i) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received July 2022 (Docket Nos. 2022-107-E and 2021-93-E, Order No. 2022-517). Per this SCPSC Order, DESC reclassified the net carrying value related to it's two simple cycle combustion turbines located at Parr to unrecovered plant regulatory asset account upon its retirement. Annual amortization was established at the level of depreciation expense ($408,876 per year) that was being recorded for the units at their retirement date of March 2023.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	20230206001 TSR Initial Study	1,600	408.1/561.6/926		
3	20231116001 TSR System Impact Study	2,701	408.1/561.6/926	6,000	253
20	Total	4,301		6,000	
21	**Generation Studies**				
22	Affected System Cluster Phase 2	1,016	408.1/561.7/926		
23	Affected System Cluster Phase 1	3,550	408.1/561.7/926		
24	Cluster Study 1 Phase 1	40,388	408.1/561.7/926		
25	Transitional Cluster Phase 1 Study	20,704	408.1/561.7/926		
26	Transitional Cluster Phase 2 Study	51,523	408.1/561.7/926		
27	20221214001 Informational Interconnection Study	1,988	408.1/561.7/926		
28	20221214002 Informational Interconnection Study	1,988	408.1/561.7/926		
29	20211221001 Facilities Study	429	408.1/561.7/926		
30	20220429001 Facilities Study	440	408.1/561.7/926		
31	20210310001Facilities Study	575	408.1/561.7/926		
32	20230309001 Informational Interconnection Study	6,003	408.1/561.7/926	10,000	253
33	20230607001 Informational Interconnection Study	4,449	408.1/561.7/926	10,000	253
34	20211101001 Facilities Study	440	408.1/561.7/926		
35	20230607002 Informational Interconnection Study	3,280	408.1/561.7/926	10,000	253
36	20210503001 Facilities Study	429	408.1/561.7/926		
37	20230629001 System Impact Study			12,000	253
38	20230703001 System Impact Study			12,000	253
39	20230713001 System Impact Study			12,000	253
40	20230706001 System Impact Study			12,000	253
41	20230720001 System Impact Study			12,000	253
42	20230719001 System Impact Study			12,000	253

43	20230714001 System Impact Study			12,000	253
44	20230729001 System Impact Study			12,000	253
45	20230728002 System Impact Study			12,000	253
46	20230802001 System Impact Study			12,000	253
47	20231106001 System Impact Study			12,000	253
48	20231204001 System Impact Study			12,000	253
49	20231207001 System Impact Study			24,000	253
50	20230210001 System Impact Study			12,000	253
51	20230208001 System Impact Study			12,000	253
52	20230203001 System Impact Study			12,000	253
53	20230829007 System Impact Study			374,700	253
54	20230828003 System Impact Study			375,000	253
55	20230828006 System Impact Study			155,000	253
56	20230829014 System Impact Study			155,000	253
57	20230829013 System Impact Study			155,000	253
58	20230825003 System Impact Study			519,000	253
59	20230829015 System Impact Study			374,999	253
60	20230829008 System Impact Study			374,700	253
61	20230829011 System Impact Study			374,700	253
62	20230829003 System Impact Study			44,950	253
63	20230825002 System Impact Study			22,500	253
64	20230829006 System Impact Study			257,000	253
65	20231130001 Informational Interconnection Study			10,000	253
66	20230829017 System Impact Study			425,000	253
67	20230210001 Security Deposit			3,000,000	253
68	20230829012 System Impact Study			374,700	253
69	20230828002 System Impact Study			317,000	253
70	20230829016 System Impact Study			124,999	253
71	20230609002 System Impact Study			455,000	253
72	20230829010 System Impact Study			255,000	253
73	20230828007 System Impact Study			130,000	253
74	20230823003 System Impact Study			129,900	253
75	20230828001 System Impact Study			129,900	253
76	20230823001 System Impact Study			129,900	253
77	20230828005 System Impact Study			110,000	253
78	20230829005 System Impact Study			255,000	253
79	20230829004 System Impact Study			75,000	253

80	20230815001 System Impact Study			674,800	253
81	20230727002 System Impact Study			129,900	253
82	20230728001 System Impact Study			34,900	253
83	20230828004 System Impact Study			330,000	253
84	20230829018 System Impact Study			275,000	253
85	20230829009 System Impact Study			255,000	253
86	20230825001 System Impact Study			155,000	253
39	Total	137,202		[a]11,192,548	
40	Grand Total	141,503		11,198,548	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: StudyCostsReimbursements

Column (d) represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Accumulated Deferred Income Taxes	29,618,415	677,531	282	3,962,314	26,333,632
2	[a] Gas Water Heater Rebate Program (12/2019-11/2028)	7,120,494	8,111,528	912	7,760,045	7,471,977
3	[b] MGP Environmental Remediation	38,439,532	19,297,148	735	22,339,313	35,397,367
4	[c] Decommissioning Asset Ret. Obligation	36,333,529	37,488,279	128/131	54,037,583	19,784,225
5	[d] Deferred ARO Accretion & Depreciation Costs	333,936,144	66,234,092	108	15,787,717	384,382,519
6	[e] Interest Rate Derivatives	277,919,893	229,876	244/427	5,184,022	272,965,747
7	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	17,912,675	1,237,909	[ah] see footnote	6,424,204	12,726,380
8	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	100,011,352	9,374,888	[ai] see footnote	37,139,487	72,246,753
9	[f] Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	3,587,255		530	183,816	3,403,439
10	[g] Deferred Capacity Charges (9/2021-8/2024)	1,185,839		555	711,504	474,335
11	[h] Electric Demand Side Management	61,762,125	37,952,197	254/908	33,733,564	65,980,758
12	[i] Gas Demand Side Management	489,477	368,433	232/921	68,568	789,342
13	[j] Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	6,247,651		555	282,658	5,964,993
14	[k] Economic Development Grants (1/2012-5/2032)	6,929,010	3,280,287	921	960,911	9,248,386
15	[l] Major Maintenance Accrual and Interest	6,021,656	4,564,954	[aj] see footnote	9,140,408	1,446,202
16	[m] Deferred Pension Cost-Gas (11/2013-1/2027)	4,189,566		926	1,029,507	3,160,059
17	[n] Deferred Pension Cost-Electric (1/2013-7/2044)	42,774,590		926	1,987,834	40,786,756
18	[o] Deferred Pollution Control Costs - Wateree (1/2013-9/2040)	18,784,316		407.3	1,061,940	17,722,376
19	[p] Research and Development Grant (1/2013-12/2047)	2,500,000		930.2	100,000	2,400,000
20	[q] Amount Undercollected-Gas Cost Adjustment	37,882,567	178,770,468	[ak] see footnote	212,775,584	3,877,451
21	[r] Amount Undercollected-Elec Fuel Adjustment Clause	452,644,682	152,111,492	449	457,253,664	147,502,510
22	Gas WNA Cap - Winter 2023/2024		1,552,793			1,552,793

23	[s] Fukushima Compliance Costs (9/2021-8/2031)	3,900,000		524	450,000	3,450,000
24	[t] Cyber Compliance Costs (9/2021-12/2031)	7,574,242		407.3/524	848,619	6,725,623
25	[u] CIPv5 Compliance Costs (9/2021-6/2032)	22,164,334		407.3/566	2,346,450	19,817,884
26	[v] Gas Pipeline Integrity Costs	10,573,343	5,403,441	887	3,210,184	12,766,600
27	[w] Net Operating Loss Excess Deferred Tax Assets	97,037,380		190/410.2	30,391,414	66,645,966
28	[x] Deferred Transmission Operating Costs (9/2021-9/2063)	77,338,215		407.3	1,900,692	75,437,523
29	[y] Deferred Storm Damage Costs	47,596,014	981,160	571/593	4,389,969	44,187,205
30	[z] Undercollected Distributed Energy Resources and Net Metering Costs	9,312,412	26,422,421	[al] see footnote	25,628,296	10,106,537
31	[aa] Deferred AMI Operating Costs (9/2021-5/2078)	4,716,847		407.3	85,157	4,631,690
32	Deferred Costs Pursuant to SC Act 62	2,272,193	2,619,064			4,891,257
33	[ab] 2020 Electric Rate Case Incremental Exp (9/2021-7/2037)	2,618,799		928	180,048	2,438,751
34	[ac] 2024 Electric Rate Case Incremental Exp		311,422			311,422
35	[ad] 2023 Gas Rate Case Incremental Exp	29,297	1,075,995	928	100,000	1,005,292
36	Electric Cost Benefit Analysis	170,000	639,190			809,190
37	Canady's Ash Pond Closure Costs	2,386,480	1,912,182	143/232	689,229	3,609,433
38	Wholesale Fuel Undercollection	16,976,910	263,040	447	14,952,799	2,287,151
39	[ae] Amt. Undercollected - Vegetation Mgmt Accrual	5,098,973	4,458,726	571/593	901,762	8,655,937
40	[af] Undercollected Electric Pension Expense		7,045,837	926	280,902	6,764,935
41	[ag] Green Therm RNG		9,844	920	347	9,497
44	TOTAL	1,796,056,207	572,394,197		958,280,511	1,410,169,893

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 89-245-G

SCPSC Docket No. 2008-155-G

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2005-113-G

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2003-84-E

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2003-84-E

Includes uncollected costs, including deferred depreciation and accretion expense, related to legal obligations associated with the future retirement of generation, transmission and distribution properties.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2007-292-E

SCPSC Docket No. 2009-489-E

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2008-230-E

SCPSC Docket No. 2020-125-E

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket Nos. 2016-40-E, 2018-42-E, 2019-57-E, 2020-41-E, 2021-34-E, 2022-52-E, 2023-42-E, and 2024-52-E.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2021-361-G

SCPSC Docket No. 2023-243-G

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2012-246-E

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E

SCPSC Docket No. 2012-218-E

SCPSC Docket No. 2017-210-E

SCPSC Docket No. 2019-159-E

SCPSC Docket No. 2020-125-E

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-35-G

SCPSC Docket No. 2013-6-G

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-36-E

SCPSC Docket No. 2009-489-E

SCPSC Docket No. 2012-218-E

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2008-393-E

SCPSC Docket No. 2012-218-E

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2011-513-E

SCPSC Docket No. 2012-218-E

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2023-5-G

Per SCPSC Docket No. 2005-5-G, commodity and demand components of purchased gas cost are recovered separately. Balances for these components as of December 31, 2023 are as follows:

Commodity	$	10,763,556
Demand		(6,886,105)
Total	$	3,877,451

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2023-2-E

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2012-277-E

SCPSC Docket No. 2020-125-E

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2015-372-E

SCPSC Docket No. 2020-125-E

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2014-416-E

SCPSC Docket No. 2020-125-E

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2018-6-G

In the docket referenced above, the SCPSC authorized amortization in a levelized annual amount of $3,182,300 beginning in November 2018.

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2017-381-A

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2017-370-E

SCPSC Docket No. 2020-125-E

(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E

SCPSC Docket No. 2012-218-E

SCPSC Docket No. 2020-125-E

Pursuant to the comprehensive settlement agreement approved by the SCPSC in DESC's retail electric base rate case (Docket No. 2020-125-E), annual amortization of $4,389,969 began September 2021. The SCPSC's order also authorized additional incremental storm cost deferrals to this account. Therefore, the actual period over which the balance will be amortized will change as additional qualifying deferrals are incurred and recognized.

(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2018-2-E

SCPSC Docket No. 2019-2-E

SCPSC Docket No. 2020-2-E

SCPSC Docket No. 2021-2-E

SCPSC Docket No. 2022-2-E

SCPSC Docket No. 2023-2-E

SCPSC Docket No. 2024-2-E

(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2019-241-EG

SCPSC Docket No. 2020-125-E

(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2020-125-E

(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2024-34-E

(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
SCPSC Docket No. 2023-70-G
(ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Pursuant to the Comprehensive Settlement Agreement approved by the SCPSC in DESC's Retail Electric Base Rate Case (Docket No. 2020-125-E), the SCPSC approved a Vegetation Management accrual under which DESC is allowed to recover $27,679,292 annually. Amounts under/(over) collected are deferred as a regulatory asset or regulatory liability, as applicable.
(af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
SCPSC Docket No. 2012-218-E SCPSC Docket No. 2023-59-E In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.
(ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
SCPSC Docket No. 2022-394-G
(ah) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
107 / 143 / 182.2 / 183 / 186 / 253 / 926
(ai) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
107 / 143 / 182.2 / 183 / 186 / 253 / 926
(aj) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
505 / 513 / 553 / 555
(ak) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
173 / 480 / 481 / 481.1 / 904
(al) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
232 / 407.3 / 440 / 442

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Noncurrent Receivable - Post Retirement Benefits	30,146,300	35,139,009	143/253	36,445,404	28,839,905
2	Progress Payments/Plant Equipment	1,291,042				1,291,042
3	Directors' Endowment	66,003				66,003
4	Long Term PowerPlant Service Agreement (2007-2028)	337,932		107/553	65,406	272,526
5	Lease Buyout Costs (2009-2057)	5,468,783	5,614,489	588/880	5,468,783	5,614,489
6	Workers' Comp Reserve	709,597	269,364	925	85,129	893,832
7	Hydro Relicense	15,158,647	1,234,984	242	250,044	16,143,587
8	Interconnection Study Deposits		2,692,800			2,692,800
9	Other	(186,966)	41,086,178	[a] see footnote	41,111,695	(212,483)
47	Miscellaneous Work in Progress	21,269,540				22,349,635
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	74,260,878				77,951,336

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

146 / 184 / 234 / 236.2

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Net Operating Loss and Income Tax Credit Carryover	303,428,698	201,193,552
3	Remeasurement of Accumulated Deferred Income Taxes	109,323,696	107,430,710
4	Other Post Employment Benefits	34,449,295	16,820,641
7	Other	[a]338,193,323	[b]295,392,573
8	TOTAL Electric (Enter Total of lines 2 thru 7)	785,395,012	620,837,476
9	Gas		
10	Asset Retirement Obligation		
11	Other Post Employment Benefits	2,974,881	2,827,236
12	Environmental Remediation		
13	Incentive Compensation	552,302	513,101
14	Remeasurement of Accumulated Deferred Income Taxes		
15	Other	[c]27,529,223	[d]27,250,699
16	TOTAL Gas (Enter Total of lines 10 thru 15)	31,056,406	30,591,036
17.1	Other (Specify) Non Operating	[e]250,011,155	[f]214,074,718
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,066,462,573	865,503,230

Notes

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Rate Refund due to Customers	$	105,810,704
Reg Liab EDIT Abandonment		98,423,834
Nuclear Decommissioning trust		59,799,363
Nuclear Unrecovered Plant		15,962,362
Fuel Impairment		19,115,584
Unamortized Investment Tax Credits		4,403,857
Short Term Incentive Plan		6,031,905
Reacquired Debt		8,366,946
Executive Deferred Compensation Plan		6,113,262
Early Retirement Programs		2,647,447
Reserve for bad debts		85,094
Directors Fee		3,481,241
Nuclear Refueling Costs		3,507,528
Reg Liab - Customer Refund		1,124,323
All Other		3,319,873
Total	$	338,193,323

(b) Concept: AccumulatedDeferredIncomeTaxes

Rate Refund due to Customers	$	79,824,525
Regulatory Liability EDIT Abandonment		92,304,218
Nuclear Decommissioning trust		62,781,058
Nuclear Unrecovered Plant		9,747,139
Fuel Impairment		14,726,135
Unamortized Investment Tax Credits		3,990,765
Short Term Incentive Plan		5,585,989
Reacquired Debt		8,612,642
Executive Deferred Compensation Plan		6,113,262
Early Retirement Programs		2,647,447
Reserve for bad debts		164,261
Directors Fee		3,481,241
Reg Liab - Customer Refund		—
Nuclear Refueling Costs		1,392,409
All Other		4,021,482
Total	$	295,392,573

(c) Concept: AccumulatedDeferredIncomeTaxes

Reg Liab EDIT tax reform	$	17,785,254
Environmental Cleanup		7,201,723
Payroll		300,546
Unamortized Investment Tax Credits		313,570
Executive Deferred Compensation Plan		504,133
Early Retirement Programs		235,359
Directors Fees		287,082
Reserve for Injuries and Damages		17,424
All Other		884,132
Total	$	27,529,223

(d) Concept: AccumulatedDeferredIncomeTaxes

Reg Liab EDIT tax reform	$	17,471,560
Environmental Cleanup		7,480,375
Payroll		—
Unamortized Investment Tax Credits		298,958
Executive Deferred Compensation Plan		504,133
Early Retirement Programs		235,359
Rate Refund		202,849
Directors Fees		287,082
Reserve for Injuries and Damages		19,693
All Other		750,690
Total	$	27,250,699

(e) Concept: AccumulatedDeferredIncomeTaxes		
Toshiba Settlement	$	191,951,890
Columbia Energy Center		33,369,118
Contingent Claims Reserve		4,983,858
Income Tax Credit Carryover		12,524,002
Accrued Interest		4,559,335
Severance		426,807
Other Post Employee Benefits		294,737
Early Retirement Programs		20,322
Directors Endowment		32,305
All Other		1,848,781
Total	$	250,011,155

(f) Concept: AccumulatedDeferredIncomeTaxes		
Toshiba Settlement	$	175,235,390
Columbia Energy Center		28,551,475
Income Tax Credit Carryover		3,152,666
Accrued Interest		4,534,075
Severance		375,227
Other Post Employee Benefits		294,737
Early Retirement Programs		20,322
Contingent Claims Reserve		—
Directors Endowment		32,305
All Other		1,878,521
Total	$	214,074,718

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	[a] Common Stock	50,000,000			40,296,147	576,405,122				
6	Total	50,000,000			40,296,147	576,405,122				
7	Preferred Stock (Account 204)									
8	[b] Preferred Stock	20,000,000			[c] 1,000	100,000				
12	Total	20,000,000			1,000	100,000				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: CapitalStockDescription

No par value

(b) Concept: CapitalStockDescription

No par value

(c) Concept: PreferredStockSharesOutstanding

These shares are held by SCANA Corporation and do not pay a dividend.

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	3,506,548,233
3	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	3,506,548,233
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	0
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	0
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	0
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	0
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	9,751,823
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	9,751,823
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	3,516,300,056
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	3,516,300,056

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense, no par value	4,335,379
22	TOTAL	4,335,379

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	First Mortgage Bonds:		[a]0										
3	6.625% Series, due 2032	221	300,000,000		2,928,187		2,397,000	01/31/2002	02/01/2032	01/31/2002	02/01/2032	300,000,000	19,875,000
4	4.50% Series, due 2064	221	375,000,000		3,900,440		4,803,750	[e]06/01/2014	06/01/2064	[f]06/01/2014	06/01/2064	52,051,000	2,342,295
5	5.25% Series, due 2035	221	100,000,000		1,032,840		1,821,000	03/08/2005	03/01/2035	03/08/2005	03/01/2035	100,000,000	5,250,000
6	5.30% Series, due 2033	221	300,000,000		2,678,847		579,000	05/21/2003	05/15/2033	05/21/2003	05/15/2033	300,000,000	15,900,000
7	5.80% Series, due 2033	221	200,000,000		1,785,478		646,000	01/23/2003	01/15/2033	01/23/2003	01/15/2033	200,000,000	11,600,000
8	6.25% Series, due 2036	221	125,000,000		1,240,777		421,250	06/27/2006	07/01/2036	06/27/2006	07/01/2036	125,000,000	7,812,500
9	6.05% Series, due 2038	221	250,000,000		2,611,037		242,500	01/14/2008	01/15/2038	01/14/2008	01/15/2038	250,000,000	15,212,725
10	6.05% Series, due 2038	221	110,000,000		962,500		5,365,800	06/24/2008	01/15/2038	06/24/2008	01/15/2038	110,000,000	6,473,500
11	4.35% Series, due 2042	221	250,000,000		2,559,708		207,500	01/30/2012	02/01/2042	01/30/2012	02/01/2042	59,424,000	2,584,944
12	4.35% Series, due 2042	221	250,000,000		2,559,709	(21,570,000)		07/13/2012	02/01/2042	07/13/2012	02/01/2042	59,424,000	2,584,944
13	6.05% Series, due 2038	221	175,000,000		1,916,924		728,000	03/17/2009	01/15/2038	03/17/2009	01/15/2038	175,000,000	10,681,275
14	5.50% Series, due 2039	221	150,000,000		1,517,157		1,179,000	12/09/2009	12/15/2039	12/09/2009	12/15/2039	150,000,000	8,250,000
15	5.45% Series, due 2041	221	250,000,000		2,187,500		917,500	01/27/2011	02/01/2041	01/27/2011	02/01/2041	250,000,000	13,625,000
16	5.45% Series, due 2041	221	100,000,000		1,361,577	(2,799,000)		05/24/2011	02/01/2041	05/24/2011	02/01/2041	100,000,000	5,450,000
17	4.60% Series, due 2043	221	400,000,000		4,234,911		2,000,000	06/14/2013	06/15/2043	06/14/2013	06/15/2043	400,000,000	18,400,000
18	5.10% Series, due 2065	221	500,000,000		5,325,812		4,035,000	05/22/2015	06/01/2065	05/22/2015	06/01/2065	500,000,000	25,500,000
19	4.10% Series, due 2046	221	425,000,000		3,718,750		875,500	06/13/2016	06/15/2046	06/13/2016	06/15/2046	49,894,000	2,045,654
20	4.25% Series, due 2028	221	400,000,000		2,600,000		1,000,000	08/17/2018	08/15/2028	08/17/2018	08/15/2028	53,251,000	2,263,168
21	2.3% Series, due 2031	221	400,000,000		3,097,830		248,000	11/29/2021	12/01/2031	11/29/2021	12/01/2031	400,000,000	9,200,000

22	6.25% Series, due 2053, SCPSC Order No. 2016-564 issued on August 18, 2016	221	500,000,000		4,709,999		2,830,000	10/06/2023	10/15/2053	10/06/2023	10/15/2053	500,000,000	7,378,472
23	Pollution Control Facilities Revenue Bonds:												
24	4% Industrial Revenue, due 2028	221	[b]39,480,000		426,014	(2,694,115)		01/15/2013	02/01/2028	01/15/2013	02/01/2028	39,480,000	1,579,200
25	3.625% Industrial Revenue, due 2033	221	[c]14,735,000		158,164		258,157	01/15/2013	02/01/2033	01/15/2013	02/01/2033	14,735,000	534,144
26	Variable Industrial Revenue, due 2038	221	[d]35,000,000		500,836			12/10/2008	12/01/2038	12/10/2008	12/01/2038	34,555,000	1,042,685
27	Amortization of Interest Rate Derivative Contracts:												
28	6.625% $300 Million due 2/1/2032	221								01/31/2002	02/01/2032		(50,978)
29	5.80% $200 Million due 1/15/2033	221								01/23/2003	01/15/2033		(7,781)
30	6.25% $125 Million due 7/1/2036	221								06/27/2006	07/01/2036		(290,039)
31	5.30% $300 Million due 5/21/2033	221								05/21/2003	05/15/2033		466,522
32	5.25% $100 Million due 3/1/2035	221								03/08/2005	03/01/2035		61,349
33	6.05% $250 Million due 1/15/2038	221								01/14/2008	01/15/2038		404,482
34	6.05% $110 Million due 1/15/2038	221								06/24/2008	01/15/2038		(14,481)
35	6.05% $175 Million due 1/15/2038	221								03/17/2009	01/15/2038		771,286
36	5.50% $150 Million due 12/15/2039	221								12/09/2009	12/15/2039		(556,452)
37	5.45% $250 Million due 2/1/2041	221								01/27/2011	02/01/2041		442,234
38	5.45% $100 Million due 2/1/2041	221								05/24/2011	02/01/2041		561,170
39	4.35% $250 Million due 2/01/2042	221								01/30/2012	02/01/2042		(76,381)
40	4.60% $75 Million due 6/14/2043	221								06/14/2013	06/15/2043		612,560
41	4.60% $75 Million due 6/14/2043	221								06/14/2013	06/15/2043		617,336
42	4.60% $90 Million due 6/14/2043	221								06/14/2013	06/15/2043		(369,775)
43	4.60% $80 Million due 6/14/2043	221								06/14/2013	06/15/2043		(330,604)
44	4.60% $80 Million due 6/14/2043	221								06/14/2013	06/15/2043		(323,152)
45	$35 Million SIFMA due 11/30/2038	221								12/01/2013	11/30/2038		61,574
46	4.50% $300 Million due 06/01/2064 and $75 Million due 6/1/2064	221								06/01/2014	06/01/2064		23,949
47	5.10% $500 Million due 06/01/2065	221								06/01/2015	06/01/2065		491,705
48	4.10% $425 Million due 06/15/2046	221								06/13/2016	06/15/2046		249,073
49	Subtotal		5,649,215,000		54,014,997	(27,063,115)	30,554,957					4,222,814,000	198,329,103
50	Reacquired Bonds (Account 222)												
51													
52													
53													
54	Subtotal												
55	Advances from Associated Companies (Account 223)												
56													

57													
58													
59	Subtotal												
60	Other Long Term Debt (Account 224)												
61	[g] Contract on Natural Gas Distribution System, Fort Jackson due 2069	224	1,001,700									969,283	34,060
62	[h] Contract on Natural Gas Distribution System Acquired from Charleston AFB	224	424,844									106,353	5,445
63	Commitment Fees	224											209,190
64	[i] See Footnote												[j]0
65	Subtotal		1,426,544									1,075,636	248,695
33	TOTAL		5,650,641,544									4,223,889,636	198,577,798

FOOTNOTE DATA

(a) Concept: BondsPrincipalAmountIssued

With respect to unamortized amounts (premium, discount or expense) of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

(b) Concept: BondsPrincipalAmountIssued

DESC issued $39,480,000 First Mortgage Bonds, Pledge Series, on January 15, 2013 at an interest rate of 4.000% with a maturity of February 1, 2028 to U. S. Bank National Association, as Trustee under the Bond Trust Indenture dated as of January 1, 2013, for the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2013.

(c) Concept: BondsPrincipalAmountIssued

DESC issued $14,735,000 First Mortgage Bonds, Pledge Series, on January 15, 2013 at an interest rate of 3.625% with a maturity of February 1, 2033 to U. S. Bank National Association, as Bond Trustee to the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2013.

(d) Concept: BondsPrincipalAmountIssued

DESC issued $35,000,000 First Mortgage Bonds, Pledge Series on December 10, 2008 at a floating rate with a maturity of December 1, 2038 to The Bank of New York Mellon Trust Company, N.A., as Bond Trustee to the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2008. Currently, there are $34,555,000 outstanding.

(e) Concept: NominalDateOfIssue

Debt was issued in two tranches, a tranche of $300,000,000 was issued June 1, 2014, and an additional tranche of $75,000,000 was issued on June 13, 2016

(f) Concept: AmortizationPeriodStartDate

Debt was issued in two tranches, a tranche of $300,000,000 was issued June 1, 2014, and an additional tranche of $75,000,000 was issued on June 13, 2016.

(g) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2018, the Company was awarded the contract for the privatization of the natural gas distribution system at Fort Jackson for a stated contract amount of $1,364,700. The Company submitted a revised purchase price proposal of $1,001,700 which was approved in February 2021 by the Department of defense through its contracting agent. On November 19, 2019, ownership of the system transferred to the Company, and the Company recorded assets totaling $1,001,700 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 50 years. As of December 31, 2023, the outstanding amount related to this obligation was $969,283.

(h) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of December 31, 2023, the outstanding amount related to this obligation was $106,353.

(i) Concept: ClassAndSeriesOfObligationCouponRateDescription

The Company has authorization from the South Carolina Public Service Commission to issue up to $2.0 billion of First Mortgage Bonds (State Commission Order No. 2016-564). As of December 31, 2023, the Company had issued $1.34 billion under such authorization. These issuances are included in Account 221 - Bonds.

(j) Concept: InterestExpenseOtherLongTermDebt

The interest expense of $44,700,692 included in account 430 - Interest on Debt to Associated Companies is related to short-term debt and therefore is not included in this schedule.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	374,554,944
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Tax Interest Capitalized	
6	Deferred Fuel	353,837,047
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	380,503,397
11	NND Regulatory Asset Amortization	138,405,300
12	Other	[a]159,475,008
14	Income Recorded on Books Not Included in Return	
15	Penalties	
16	Deferred Fuel	
19	Deductions on Return Not Charged Against Book Income	
20	Tax Unrecovered Nuclear Project Costs	
21	Tax Depreciation and Amortization	534,215,203
22	Contingency Claims	20,205,382
23	Net Operating Loss	171,494,390
24	Reg Rate Refund	103,339,999
25	NND Regulatory Liability - Toshiba	67,000,000
26	Other	[b]27,330,376
27	Federal Tax Net Income	483,190,346
28	Show Computation of Tax:	
29	Tax @ 21%	101,469,973
30	Credits	(7,429,930)
31	Other	(6,459,077)
32	Other (Return to Provision)	(3,239,556)
33	Current Federal Income Tax Expense Recorded	84,341,410

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Total Net Book Income Tax (Including Investment Tax Credit)	$79,684,515
State taxes	69,663,440
Employee Benefit Plan	8,222,074
Meals and Lobbing	800,000
Restricted Stock	934,223
AFUDC	170,756
Total	$159,475,008

(b) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Nuclear Outage Deferral	(9,299,266)
Accrued Interest	(3,534,157)
Environmental Cleanup	(14,496,952)
All other	(1)
Total	($27,330,376)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1		Other Taxes and Fees			0	0				0	0				
2					0	0				0					
3	**Subtotal Federal Tax**				0	0				0	0				
4	**Subtotal State Tax**				0	0				0	0				
5	**Subtotal Local Tax**				0	0				0	0				
6	Other	Other Taxes			0	0				0	0				
7	**Subtotal Other Tax**				0	0				0	0				
8	County Property Tax	Property Tax			218,763,266	0	230,882,715	218,796,562		230,849,419	0	204,796,688			26,086,027
9	Municipal Property Tax	Property Tax			11,587,204	0	12,640,891	11,973,087		12,255,008	0	11,212,674			1,428,217
10	**Subtotal Property Tax**				230,350,470	0	243,523,606	230,769,649		243,104,427	0	216,009,362			27,514,244
11	**Subtotal Real Estate Tax**				0	0				0	0				
12	**Subtotal Unemployment Tax**				0	0				0	0				
13	**Subtotal Sales And Use Tax**				0	0				0	0				
14	Federal Income Taxes	Income Tax			0	0	84,341,411	125,348,309	[a]41,006,898	0	0	102,001,576			(17,660,165)
15	State Income Taxes	Income Tax			40,618,190	0	(64,968,854)	(59,180,229)	[b]15,535,028	50,364,593	0	(68,426,927)			3,458,073
16	**Subtotal Income Tax**				40,618,190	0	19,372,557	66,168,080	56,541,926	50,364,593	0	33,574,649			(14,202,092)
17	Excise	Excise Tax			0	0	699	699		0	0	699			
18	**Subtotal Excise Tax**				0	0	699	699		0	0	699			
19	**Subtotal Fuel Tax**				0	0				0	0				
20	**Subtotal Federal Insurance Tax**				0	0				0	0				
21	Franchise	Franchise Tax			0	0	16,060,028	525,000	(15,535,028)	0	0	13,098,340			2,961,688

22	**Subtotal Franchise Tax**				0	0	16,060,028	525,000	[c](15,535,028)	0	0	13,098,340			2,961,688
23	Electric Generation	Miscellaneous Other Tax			625,000	0	6,595,280	6,595,280		625,000	0	6,557,022			38,258
24	**Subtotal Miscellaneous Other Tax**				625,000	0	6,595,280	6,595,280		625,000	0	6,557,022			38,258
25	**Subtotal Other Federal Tax**				0	0				0	0				
26	**Subtotal Other State Tax**				0	0				0	0				
27	**Subtotal Other Property Tax**				0	0				0	0				
28	Total Other Sales and Use Tax	Other Use Tax			(11,759)	0	5,339	14,164,854	13,421,992	(749,282)		3,746			1,593
29	**Subtotal Other Use Tax**				(11,759)	0	5,339	14,164,854	[d]13,421,992	(749,282)	0	3,746			1,593
30	**Subtotal Other Advalorem Tax**				0	0				0	0				
31	**Subtotal Other License And Fees Tax**				0	0				0	0				
32	FUTA	Payroll Tax			1,545	0	109,636	109,537	(1,644)	0	0	96,891			12,745
33	FICA	Payroll Tax			(14,713)	0	19,125,216	19,926,571	816,068	0	0	16,477,291			2,647,925
34	SUTA	Payroll Tax			6,574	0	89,379	89,793	(6,160)	0	0	78,989			10,390
35	Other Payroll	Payroll Tax			817,251	0	51,764	5,969	(863,046)	0	0	45,746			6,018
36	**Subtotal Payroll Tax**				810,657	0	19,375,995	20,131,870	[e](54,782)	0	0	16,698,917			2,677,078
37	**Subtotal Advalorem Tax**				0	0				0	0				
38	**Subtotal Other Allocated Tax**				0	0				0	0				
39	**Subtotal Severance Tax**				0	0				0	0				
40	**Subtotal Penalty Tax**				0	0				0	0				
41	**Subtotal Other Taxes And Fees**				0	0				0	0				
40	TOTAL				272,392,558	0	304,933,504	338,355,432	54,374,108	293,344,738	0	285,942,735			18,990,769

FOOTNOTE DATA

(a) Concept: TaxAdjustments

Reclassified amount to accounts:

146 Accounts Receivable Associated Company $ 41,006,898

(b) Concept: TaxAdjustments

Reclassified amount to accounts:

Franchise Tax $15,535,028

(c) Concept: TaxAdjustments

Reclassified amount to accounts:

State Income Taxes $ (15,535,028)

(d) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $ 13,421,992

(e) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $ (54,782)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

			Deferred for Year		Allocations to Current Year's Income					
Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1	Electric Utility									
2	3%									
3	4%	87,235			411.4	7,451		79,784	58.4 Years	
4	7%									
5	10%	9,926,204			411.4	978,445		8,947,759	58.4 Years	
6	8%	3,197,095			411.4	254,343		2,942,752	58.4 Years	
7	20%	21,785			411.4	2,347		19,438	58.4 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,232,319				1,242,586		11,989,733		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	4%	4,370			411.4	340		4,030	58.0 Years	
12	10%	300,062			411.4	14,680		285,382	58.0 Years	
13	8%	650,281			411.4	28,816		621,465	58.0 Years	
14	20%	2,618			411.4	119		2,499	58.0 Years	
15	Gas Utility									
16	Total Gas	957,331				43,955		913,376		
47	OTHER TOTAL									
48	GRAND TOTAL	14,189,650				1,286,541		12,903,109		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Gas Environmental Remediation	20,060,000	131/182.3	20,060,000	5,749,608	5,749,608
2	Other Environmental Remediation	1,450,486	182.3	850,486	973,212	1,573,212
3	Long-Term Disability	127,646				127,646
4	Santee River Basin Accord	675,928	131	94,209		581,719
5	Municipal Nonstandard Service Fund Matching Obligation	2,980,103	186	2,980,103	2,066,479	2,066,479
6	SRS Substation	1,227,616	456	96,284		1,131,332
7	Interconnection Study Deposits	6,009,865	243/456	2,280,680	14,006,029	17,735,214
8	CIAC Obligations	15,726,280	107	1,461,670	2,116,732	16,381,342
9	Noncontrolling Interest - SCFC	5,709,895				5,709,895
10	FIN 48 Penalty	3,502,106				3,502,106
11	Parr Habitat Enhancement Fund		535	161,000	277,659	116,659
12	Parr Relicensing Recreation Management Plan		186	215,774	900,500	684,726
13	Electric Vehicle Charge Station Interest		419	743	12,638	11,895
14	Other	3,229,538	421/440	2,472,131	466,756	1,224,163
47	TOTAL	60,699,463		30,673,080	26,569,613	56,595,996

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	10,282,215		244,702							10,037,513
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	10,282,215		244,702							10,037,513
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	10,282,215		244,702							10,037,513
18	Classification of TOTAL										
19	Federal Income Tax	8,938,135		212,715							8,725,420
20	State Income Tax	1,344,080		31,987							1,312,093
21	Local Income Tax										

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	1,120,251,789	152,029,913	122,626,871							1,149,654,831
3	Gas	124,505,524	17,136,263	12,874,742			190/282	60,467			128,706,578
4	Other (Specify)	5,780,131			6,578,549	3,690,547	190/282	1,071,556			7,596,577
5	Total (Total of lines 2 thru 4)	1,250,537,444	169,166,176	135,501,613	6,578,549	3,690,547		1,132,023			1,285,957,986
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,250,537,444	169,166,176	135,501,613	6,578,549	3,690,547		1,132,023			1,285,957,986
10	Classification of TOTAL										
11	Federal Income Tax	1,024,191,588	135,183,359	111,095,474	5,267,533	3,681,108		905,165			1,048,960,733
12	State Income Tax	226,345,856	33,982,817	24,406,139	1,311,016	9,439		226,858			236,997,253
13	Local Income Tax										

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Unrecovered Nuclear Proj Costs	569,304,655	2,501,487	37,507,832							534,298,310
4	Regulatory Asset - ARO										
5	Employee Benefit Plan Costs										
6	Unrecovered Plant Canadys	13,588,589	2,951	73,067							13,518,473
7	Prepayments	12,261,635	119,495	4,826							12,376,304
8	[a] All Other	281,435,821	33,381,194	108,286,566			190/282/283	35,365,603	190/282/283	12,714	171,177,560
9	TOTAL Electric (Total of lines 3 thru 8)	876,590,700	36,005,127	145,872,291				35,365,603		12,714	731,370,647
10	Gas										
11	Employee Benefit Plan Costs										
12	Regulatory Asset - ARO										
13	Deferred Gas Costs	9,451,700	2,759,272	11,243,548							967,424
14	Pension Plan Income	4,321,131	592,809	23,940							4,890,000
15	Prepayments	2,278,435	558,966	22,574							2,814,827
16	[b] All Other	16,160,107	652,284	251,894			190/282/283	91,073			16,469,424
17	TOTAL Gas (Total of lines 11 thru 16)	32,211,373	4,563,331	11,541,956				91,073			25,141,675
18	TOTAL Other	[c]450,340				41					450,299
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	909,252,413	40,568,458	157,414,247		41		35,456,676		12,714	756,962,621
20	Classification of TOTAL										
21	Federal Income Tax	727,046,913	37,991,278	127,081,866		41	190/282/283	32,691,913	190/282/283	10,166	605,274,537
22	State Income Tax	182,205,500	2,577,180	30,332,381			190/282/283	2,764,763	190/282/283	2,548	151,688,084
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Pension plan income	$ 58,352,623	$ 814,362	$ 20,165,144	$ —	$ 39,001,841
Deferred fuel costs	117,170,579	3,358,235	83,156,302	—	37,372,512
Demand Side Management Costs	16,753,581	59,627	1,476,466	—	15,336,742
Cyber Security Costs	8,216,944	33,548	830,718	—	7,419,774
Fukushima Compliance	1,085,325	4,725	117,000	—	973,050
Deferred VCS Costs	940,884	1,930	47,792	—	895,022
Regulatory Asset Deferred Capacity	473,388	7,471	184,991	—	295,868
Grants	648,700	1,181	29,250	—	620,631
Insurance, Injuries and Damages	217,159	4,879	120,823	—	101,215
Payroll	300,546	12,648	313,194	—	—
Decommissioning	7,151,372	—	—	(4,771,786)	2,379,586
Reg Liab - Vegetation Management	1,302,011	1,255	31,072	—	1,272,194
Reg Liab - Undist Customer Refund				12,714	12,714
Reg Liab State EDIT Property	5,993,967	147,631	—	(202,403)	5,939,195
Reg Asset - DER Costs	1,728,631	619,849	25,032	—	2,323,448
Reg Asset - Major Maintenance	2,606,035	46,445	1,150,078	—	1,502,402
Reg Asset - Pollution Control	6,580,952	14,118	349,596	—	6,245,474
Reg Asset - Storm Damage	11,576,082	311,711	12,588	—	11,875,205
Reg Liab EDIT NOL	24,210,826	22,808,756	—	(30,391,414)	16,628,168
All Other	16,126,216	5,132,823	276,520	—	20,982,519
Total	$ 281,435,821	$ 33,381,194	$ 108,286,566	$ (35,352,889)	$ 171,177,560

(b) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Reacquired debt	$ 10,986,882	$ 1,149	$ 28,449	—	$ 10,959,582
Employee Costs	3,757	—	330		3,427
Demand Side Management	—	127,264	5,139		122,125
Gas Water Heater	1,684,421	96,020	3,878	—	1,776,563
Gas Pipeline Integrity	2,415,235	232,192	9,377	—	2,638,050
Gas WNA Cap	191,832	8,073	199,905	—	—
Rate Case Expense	—	7,617	308		7,309
Reg Liab State EDIT Property	309,890	68,350	—	(91,073)	287,167
Reg Asset - Gas ERTS	568,090	111,619	4,508	—	675,201
Total	$ 16,160,107	$ 652,284	$ 251,894	(91,073)	$ 16,469,424

(c) Concept: AccumulatedDeferredIncomeTaxesOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.2	Amt. Credited Acct.411.2	Adjust.	Balance at End of Year
Pension plan income	$ 449,870	—	—	—	$ 449,870
Employee Benefits	470		41	—	429
Total	$ 450,340		$ 41	—	$ 450,299

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Accumulated Deferred Income Tax Credits	4,717,427	190	427,704		4,289,723
2	[a] Nuclear Refueling Accrual	14,880,064	524/528	21,780,473	12,481,207	5,580,798
3	NOX Emission Allowance Proceeds	1,042				1,042
4	[b] Interest Rate Derivatives (3/2009-6/2043)	68,144,522	427	3,760,590	103,631	64,487,563
5	[c] Solar PPAs MTM Gains	251,078,812	175	776,682,223	701,750,199	176,146,788
6	[d] Demand Side Management Carrying Costs	292,214	182.3	267,828	62,749	87,135
7	SO2 Emission Allowance Proceeds	1,183			39	1,222
8	[e] Overcollected Electric Pension Expense	1,223,906	926	6,065,811	4,841,905	
9	[f] Monetization-Toshiba Settlement (2/2019-1/2039)	769,295,299	[p] see footnote	67,000,000		702,295,299
10	[g] Excess Deferred Tax Liabilities - Electric	831,975,601	[q] see footnote	33,876,189		798,099,412
11	[h] Excess Deferred Tax Liabilities - Gas	71,173,323	[r] see footnote	1,355,022		69,818,301
12	[i] Customer Refunds Merger Approval Order - Electric	424,091,000	[s] see footnote	103,340,000		320,751,000
13	[j] Deferred Gain on Sale of Turbine Generator and Associated Equipment (9/2021-8/2023)	325,000	407.4	325,000		
14	[k] Revenue Subject to Refund - Tax Reform Electric Residual Balance (9/2021-9/2024)	825,113	407.4	485,901		339,212
15	[l] Amortized Excess Deferred Tax Liabilities from GENCO (9/2021-6/2026)	4,658,880	555	1,352,364		3,306,516
16	Renewable Energy Credits	2,570,320	174	584,188	1,231,732	3,217,864
17	[m] Hardeeville Retirement	1,078,575	108	590,962	144,858	632,471
18	[n] Environmental Remediation Costs	351,926	573/592	18,130	240,000	573,796
19	[o] Unprotected Plant EDIT Decrement Rider	63,977,404	190/409.1	24,910,713		39,066,691
41	TOTAL	2,510,661,611		1,042,823,098	720,856,320	2,188,694,833

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2012-218-E

SCPSC Docket No. 2020-172-E

SCPSC Docket No. 2020-125-E

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Activity is associated with the amortization of settlement amounts over the life of the related debt issuances.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents the mark to market gains associated with embedded derivatives of Solar PPAs that contain minimum production guarantees and not probable of physical settlement.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E
SCPSC Docket No. 2015-45-E
SCPSC Docket No. 2016-40-E
SCPSC Docket No. 2017-35-E
SCPSC Docket No. 2018-42-E
SCPSC Docket No. 2019-57-E
SCPSC Docket No. 2020-41-E

SCPSC Docket No. 2021-34-E

SCPSC Docket No. 2022-52-E

SCPSC Docket No. 2023-42-E

SCPSC Docket No. 2024-52-E

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2023-59-E

SCPSC Docket No. 2024-62-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents net proceeds received under or arising from the monetization of the Settlement Agreement dated as of July 27, 2017 with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E, the SCPSC ordered $1.032 billion to be credited to customers over twenty years beginning in February 2019.

In March 2022 in SCPSC Docket No. 2022-2-E, DESC applied approximately $61.3 million of this regulatory liability as a reduction to its retail electric undercollected base fuel cost balance.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The FERC jurisdictional transmission portion of these amounts was included in a compliance filing for Order No. 864 in FERC Docket No. ER20-1836. The Commission accepted DESC's compliance filing in a letter order issued on November 21, 2022.

SCPSC Docket No. 2017-381-A

Amounts related to plant-related temporary differences are being amortized using the average rate assumption method (ARAM). Under ARAM, the excess deferred tax liabilities will reverse at the weighted average rate at which the deferred taxes were built over the remaining book life of the property to which those deferred taxes relate. These reversal periods average fifty years.

For non-plant related excess deferred tax liabilities, the balances will reverse over 5 years, or in the case of Nuclear Project-related excess deferred tax liabilities, twenty years.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Amounts related to plant-related temporary differences are being amortized using the average rate assumption method (ARAM). Under ARAM, the excess deferred tax liabilities will reverse at the weighted average rate at which the deferred taxes were built over the remaining book life of the property to which those deferred taxes relate. These reversal periods average fifty years.

For non-plant related excess deferred tax liabilities, the balances will reverse over 5 years.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2017-370-E

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2020-125-E

Deferred gain related to sale of an electric power generator, a 13.8/115kV generator step-up transformer and associated equipment to Kapstone Charleston Kraft, LLC. The FERC authorized the clearing of the gain from Account 102 - Electric Plant Purchased or Sold to Account 254 - Other Regulatory Liabilities via a letter order dated July 2, 2019 issued in Docket No. AC19-145-000.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2020-125-E

By Order No. 2018-804 issued in Docket No. 2017-370-E, the SCPSC ordered the refund of amounts collected from customers and reserved for refund related to the change in the corporate federal tax rate. The Company provided the refund in accordance with the order in February 2019. However, since the refund was a volumetric calculation, a residual balance is being refunded pursuant to the SCPSC Docket above.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
SCPSC Docket No. 2020-125-E By order dated April 28, 2020, the FERC authorized modifications to South Carolina Generating Company, Inc.'s (GENCO) formula rate to provide for the pass through of GENCO's amortized Excess Deferred Tax Liabilities to DESC.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
By Order No. 2022-517, dated July 21, 2022, the Public Service Commission of South Carolina granted Dominion Energy South Carolina, Inc.'s petition in SCPSC Docket No. 2022-107-E to reclassify its net credit balance carrying value related to the retirement of its Hardeeville simple cycle combustion turbine to a regulatory liability account.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
SCPSC Docket No. 2012-218-E

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities
The FERC jurisdictional transmission portion of these amounts was included in a compliance filing for Order No. 864 in FERC Docket No. ER20-1836. The Commission accepted DESC's compliance filing in a letter order issued on November 21, 2022. SCPSC Docket No. 2020-125-E In connection with the comprehensive settlement agreement approved by the SCPSC (Docket No. 2020-125-E) in DESC's retail electric base rate case, unprotected plant-related excess deferred tax liabilities will be returned to retail customers through a volumetric decrement rate rider which began in September 2021. Amortization will be matched with the rider decrements, with certain portions of the amortization affecting the Open Access transmission Tariff (OATT) formula rate, which was accepted by the FERC by letter order issued in Docket No. ER20-1836.

(p) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
131 / 182.3 / 440 / 442 / 444 / 445

(q) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
190 / 254 / 282 / 283

(r) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
190 / 283 / 410

(s) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment
440 / 442 / 444 / 445

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,159,870,303	1,374,324,866	8,048,075	8,485,891	[(n)]681,264	669,251
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	820,009,389	968,218,949	7,074,407	7,186,928	[(o)]103,379	102,179
5	Large (or Ind.) (See Instr. 4)	371,689,254	532,789,860	5,344,833	5,568,616	[(p)]776	764
6	(444) Public Street and Highway Lighting	15,723,587	18,309,110	58,741	74,957	[(q)]1,053	1,050
7	(445) Other Sales to Public Authorities	46,642,455	56,831,542	500,021	504,003	[(r)]3,749	3,751
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[(a)]2,413,934,988	[(f)]2,950,474,327	[(k),(l)]21,026,077	[(m)]21,820,395	790,221	776,995
11	(447) Sales for Resale	[(b)]44,876,083	[(g)]87,419,199	920,991	1,159,293	9	6
12	TOTAL Sales of Electricity	2,458,811,071	3,037,893,526	21,947,068	22,979,688	790,230	777,001
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	2,458,811,071	3,037,893,526	21,947,068	22,979,688	790,230	777,001
15	Other Operating Revenues						
16	(450) Forfeited Discounts	8,475,729	7,854,221				
17	(451) Miscellaneous Service Revenues	[(c)]5,793,654	[(h)]4,829,245				
18	(453) Sales of Water and Water Power	583,330	585,775				
19	(454) Rent from Electric Property	27,346,218	29,919,061				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(d)]10,183,845	[(i)]8,782,882				
22	(456.1) Revenues from Transmission of Electricity of Others	[(e)]15,089,180	[(j)]14,686,506				

23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	67,471,956	66,657,690				
27	TOTAL Electric Operating Revenues	2,526,283,027	3,104,551,216				

Line12, column (b) includes $ 124,319,780 of unbilled revenues.
Line12, column (d) includes 960,366 MWH relating to unbilled revenues

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Includes the following amounts under/(over)-collected pursuant to the respondent's fuel adjustment clause:

Residential	$	(116,918,841)
Commercial	$	(104,382,072)
Industrial	$	(75,379,937)
Street Lighting	$	(896,577)
Other Public Authorities	$	(7,564,746)
	$	(305,142,173)

Includes Unmetered Sales Revenue as follows:

Residential	$	19,797,619
Commercial/Industrial	$	31,367,474
Street Lighting	$	15,364,110
Other Public Authorities	$	111,961
	$	66,641,164

In accordance with the SCPSC's Merger Approval Order, in January 2019 the Company established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which will be credited to customers over approximately 11 years beginning in February 2019.

(b) Concept: SalesForResale

This amount includes $4,757 in revenue from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This revenue is reflective of 2,541 MWH.

(c) Concept: MiscellaneousServiceRevenues

Includes $1,467,614 of reconnect and lighting disconnect charges.

Includes $3,057,953 of transmission maintenance fee revenue.

Includes $1,239,095 of returned check fees.

(d) Concept: OtherElectricRevenue

Includes $9,049,187 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $259,305 of Telecommunication Tower Rent Revenue.

Includes $265,000 in fees related to the establishment and ongoing administration of Solar Purchase Power Agreements

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

This amount includes $732 of revenue from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This revenue is reflective of 763 MWH.

(f) Concept: SalesToUltimateConsumers

Includes the following amounts under/(over)-collected pursuant to the respondent's fuel adjustment clause:

Residential	$	153,728,402
Commercial	$	135,785,130
Industrial	$	102,889,567
Street Lighting	$	1,113,199
Other Public Authorities	$	9,442,941
	$	402,959,239

Includes Unmetered Sales Revenue as follows:

Residential	$	18,869,170
Commercial/Industrial	$	29,427,948
Street Lighting	$	14,392,623
Other Public Authorities	$	100,499
	$	62,790,240

In accordance with the SCPSC's Merger Approval Order, in January 2019 the Company established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which will be credited to customers over approximately 11 years beginning in February 2019.

(g) Concept: SalesForResale

This amount does not include $4,757 of revenue from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This revenue is reflective of 2,541 MWH.

(h) Concept: MiscellaneousServiceRevenues

Includes $722,758 of reconnect and lighting disconnect charges.

Includes $2,960,794 of transmission maintenance fee revenue.

Includes $1,108,305 of returned check fees.

(i) Concept: OtherElectricRevenue
Includes $5,661,939 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.
Includes $2,261,036 associated with Timber Sales.
Includes $256,012 of Recreational Facilities Charge (Parking Fees).

(j) Concept: RevenuesFromTransmissionOfElectricityOfOthers
This amount does not include $732 of revenue from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This revenue is reflective of 763 MWH.

(k) Concept: MegawattHoursSoldSalesToUltimateConsumers
Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure the total here agrees with page 300-301, Line 10 Column D.

(l) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	72,770
Commercial/Industrial	138,201
Street Lighting	53,248
Other Public Authorities	702
	264,921

(m) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	75,188
Commercial/Industrial	141,502
Street Lighting	61,046
Other Public Authorities	699
	278,435

(n) Concept: AverageNumberOfCustomersPerMonthResidentialSales
The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(o) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercial
The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(p) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrial
The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(q) Concept: AverageNumberOfCustomersPerMonthPublicStreetAndHighwayLighting
The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(r) Concept: AverageNumberOfCustomersPerMonthOtherSalesToPublicAuthorities
The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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32					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales by Rate					
2	1	285,964	36,304,901		14,023	0.1270
3	2	28,866	4,712,576		1,629	0.1633
4	5	933	122,155		13,925	0.1309
5	6	422,731	53,781,522		13,606	0.1272
6	7	773	81,906		64,417.000	0.1060
7	8	7,133,290	941,369,113		11,942	0.1320
8	E1N	4,689	777,638		9,035	0.1658
9	E2N	47	18,609		603	0.3959
10	E5N	49	7,550		9,800	0.1541
11	E6N	6,541	1,119,202		8,166	0.1711
12	E8N	76,654	13,959,806		7,254	0.1821
13	M1N		0			0.0000
14	M2N		0			0.0000
15	M5N		0			0.0000
16	M6N		0			0.0000
17	M8N		0			0.0000
18	5SC	15,989	2,133,719			0.1334
19	Special (A)	71,549	17,653,906		331	0.2467
20	Current Year Customer Refund Amount		[a]53,785,000			
21	Toshiba Guarantee Amortization		[b]34,042,700			
41	TOTAL Billed Residential Sales	7,614,974	1,096,860,163			
42	TOTAL Unbilled Rev. (See Instr. 6)	433,101	63,010,140			
43	TOTAL	8,048,075	1,159,870,303	[c]681,264	[d]8,967	0.1441

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSalesBilled

Reflects customer refund regulatory liability amortization.

(b) Concept: ResidentialSalesBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2023.

(c) Concept: AverageNumberOfCustomersPerMonthResidentialSales

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerResidentialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial Sales by Rate					
2	3	2,188	237,085		95,130	0.1084
3	9	2,682,861	344,645,168		31,515	0.1285
4	10	3,491	811,727		1,560	0.2325
5	11	10,316	1,133,119		30,794	0.1098
6	12	145,723	16,097,174		40,603	0.1105
7	14	18,027	2,376,213		10,469	0.1318
8	16	74,916	9,564,708		17,258	0.1277
9	20	1,673,697	164,316,841		868,100	0.0982
10	21	118,658	12,514,361		271,529	0.1055
11	22	410,346	44,018,202		265,081	0.1073
12	23	412,667	31,113,329		58,952,429	0.0754
13	24	1,376,996	113,848,174		8,606,225	0.0827
14	28	1,429	175,532		71,450	0.1228
15	E9N	9,564	(352,143)		68,806	(0.0368)
16	Special (A)	133,528	27,030,899		4,905	0.2024
17	Current Year Customer Refund Amortization		[a]31,910,000			
18	Toshiba Guarantee Amortization		[b]20,569,000			
41	TOTAL Billed Small or Commercial	6,712,914	775,824,518			
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	361,493	44,184,871			
43	TOTAL Small or Commercial	7,074,407	820,009,389	[c]103,379	[d]54,910	0.1159

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2023.

(c) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerSmallOrCommercialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Industrial Sales by Rate					
2	9	138,036	15,412,929		248,714	0.1117
3	16	223	24,227		111,500	0.1086
4	20	77,569	7,427,671		1,491,712	0.0958
5	23	3,419,702	240,039,644		26,509,318	0.0702
6	24	83,193	6,735,440		7,563,000	0.0810
7	27	589,711	39,422,938		98,285,167	0.0669
8	60	1,028,194	34,570,389		257,048,500	0.0336
9	E9N	3,725	664,613		532,143	0.1784
10	Special (A)	4,480	617,003		12,274	0.1377
11	Current Yr. Customer Refund Amortization		[a]15,639,000			
12	Toshiba Guarantee Amortization		[b]11,135,400			
41	TOTAL Billed Large (or Ind.) Sales	5,214,676	359,410,043			
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	130,157	12,279,211			
43	TOTAL Large (or Ind.)	5,344,833	371,689,254	[c]776	[d]4,725,758	0.0695

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2023.

(c) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerLargeOrIndustrialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Public Street and Highway Lighting Sales by Rate					
2	3	1,403	193,948		13,362	0.1382
3	9	1,322	370,754		2,825	0.2804
4	13	4,106	574,251		9,417	0.1399
5	Special (A)	51,910	14,522,234		37,643	0.2798
6	Current Year Customer Refund Amortization		[a]49,000			
7	Toshiba Guarantee Amortization		[b]13,400			
41	TOTAL Billed Public Street and Highway Lighting	52,721	13,948,964			
42	TOTAL Unbilled Rev. (See Instr. 6)	6,020	1,774,623			
43	TOTAL	58,741	15,723,587	[c]1,053	[d]24,599	0.2677

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PublicStreetAndHighwayLightingBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: PublicStreetAndHighwayLightingBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2023.

(c) Concept: AverageNumberOfCustomersPerMonthPublicStreetAndHighwayLighting

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerPublicStreetAndHighwayLighting

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Other Sales to Public Authorities					
2	3	166,312	17,900,510		47,154	0.1076
3	9	721	111,770		7,433	0.1550
4	20	7,252	681,061		1,036,000	0.0939
5	21	290	27,161		290,000	0.0937
6	65	64,430	4,640,017		3,221,500	0.0720
7	66	260,299	19,987,739		7,437,114	0.0768
8	Special (A)	717	97,697		9,689	0.1363
9	Current Year Customer Refund Amortization		[(a)]1,957,000			
10	Toshiba Guarantee Amortization		[(b)]1,239,500			
41	TOTAL Billed Other Sales to Public Authorities	470,426	43,571,520			
42	TOTAL Unbilled Rev. (See Instr. 6)	29,595	3,070,935			
43	TOTAL	500,021	46,642,455	[(c)]3,749	[(d)]132,949	0.0933

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: OtherSalesToPublicAuthoritiesBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: OtherSalesToPublicAuthoritiesBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2023.

(c) Concept: AverageNumberOfCustomersPerMonthOtherSalesToPublicAuthorities

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerOtherSalesToPublicAuthorities

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	20,065,711	2,289,615,208			
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	960,366	124,319,780			
43	TOTAL - All Accounts	21,026,077	2,413,934,988			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	City of Orangeburg	RQ	[l] footnote	119	134	128	731,550	10,482,174	35,232,073		45,714,247
2	Town of Winnsboro	RQ	[m] footnote	11	11	10	56,083	1,395,882	3,259,933		4,655,815
3	Associated Electric Cooperative, Inc.	[a] OS	footnote				198		10,346		10,346
4	Constellation Energy Generation, LLC	[b] OS	[n] footnote				27,020		921,196		921,196
5	Duke Energy Carolinas, LLC	[c] OS	[o] footnote				217		6,249		6,249
6	Duke Energy Florida	[d] OS	[p] footnote				469		12,378		12,378
7	Macquarie Energy LLC	[e] OS	[q] footnote				54,380		2,119,199		2,119,199
8	North Carolina Electric Membership Corporation	[f] OS	[r] footnote				4,011		140,839		140,839
9	Oglethorpe Power Corporation	[g] OS	[s] footnote				2,466		120,512		120,512
10	South Carolina Public Service Authority -- Emergency	[h] OS	[t] footnote						(476,592)		(476,592)

11	Southern Company Services, Inc.	[(i)] OS	[(u)] footnote				6,139		178,319		178,319
12	Tennessee Valley Authority	[(j)] OS	[(v)] footnote				296		7,870		7,870
13	The Energy Authority, Inc	[(k)] OS	[(w)] footnote				38,162		1,589,929		1,589,929
14	Wholesale Fuel Over/Under Collection									(10,124,224)[(x)]	(10,124,224)
15	Transmission Revenue included in Energy Charges Column (i)										
15	Subtotal - RQ						[(y)]787,633	11,878,056	38,492,006		50,370,062
16	Subtotal-Non-RQ						133,358		4,630,245[(z)]	(10,124,224)	(5,493,979)
17	Total						920,991	11,878,056	43,122,251	(10,124,224)	44,876,083[(aa)]

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(b) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(c) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(d) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(e) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(f) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(g) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(h) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c)

(i) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(j) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(k) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(l) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule No. 60

(m) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule Winnsboro PSA

(n) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(o) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(p) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(q) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(r) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(s) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(t) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2

(u) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2

(v) Concept: RateScheduleTariffNumber
OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(w) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2

(x) Concept: OtherChargesRevenueSalesForResale
Over / under collection of fuel relating to wholesale customers.

(y) Concept: MegawattHoursSoldRequirementsSales

Includes Unmetered MWH Sales as follows:

Residential	72,770
Commercial/Industrial	138,201
Street Lighting	53,248
Other Public Authorities	702
	264,921

(z) Concept: EnergyChargesRevenueNonRequirementsSales
Subtotal non-RQ of $4,630,245 includes transmission revenue for OS service of $694,161. Transmission base revenue totals $651,372 and ancillary services revenue totals $42,789.

(aa) Concept: SalesForResale
This amount includes $4,757 in revenue from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This revenue is reflective of 2,541 MWH.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	10,929,760	10,165,924
5	(501) Fuel	165,725,183	265,533,645
6	(502) Steam Expenses	5,060,999	4,657,837
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,608,639	1,464,637
10	(506) Miscellaneous Steam Power Expenses	6,993,448	6,078,020
11	(507) Rents		
12	(509) Allowances	33	37
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	190,318,062	287,900,100
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,434,653	900,791
16	(511) Maintenance of Structures	788,810	669,714
17	(512) Maintenance of Boiler Plant	9,264,153	9,315,278
18	(513) Maintenance of Electric Plant	14,332,032	14,360,713
19	(514) Maintenance of Miscellaneous Steam Plant	4,473,355	4,590,590
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	30,293,003	29,837,086
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	220,611,065	317,737,186
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	11,306,626	13,049,636
25	(518) Fuel	33,087,216	38,568,241
26	(519) Coolants and Water	2,330,465	1,480,599
27	(520) Steam Expenses	8,900,412	6,184,789
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

30	(523) Electric Expenses	1,328,954	651,540
31	(524) Miscellaneous Nuclear Power Expenses	37,915,843	39,945,842
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	94,869,516	99,880,647
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	5,098,211	3,605,159
36	(529) Maintenance of Structures	1,540,881	1,961,799
37	(530) Maintenance of Reactor Plant Equipment	2,700,855	16,507,739
38	(531) Maintenance of Electric Plant	1,927,223	1,873,161
39	(532) Maintenance of Miscellaneous Nuclear Plant	23,787,508	13,214,010
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	35,054,678	37,161,868
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	129,924,194	137,042,515
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,177,402	1,965,574
45	(536) Water for Power	0	
46	(537) Hydraulic Expenses	774,060	840,362
47	(538) Electric Expenses	1,899,973	1,517,486
48	(539) Miscellaneous Hydraulic Power Generation Expenses	506,710	345,457
49	(540) Rents	1,694	10,998
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	5,359,839	4,679,877
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	290,928	283,484
54	(542) Maintenance of Structures	902,372	490,486
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,100,383	711,564
56	(544) Maintenance of Electric Plant	1,709,892	2,610,705
57	(545) Maintenance of Miscellaneous Hydraulic Plant	917,779	969,486
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,921,354	5,065,725
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	10,281,193	9,745,602
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	2,008,751	2,187,595
63	(547) Fuel	276,383,714	617,450,624
64	(548) Generation Expenses	7,569,085	8,612,218
64.1	(548.1) Operation of Energy Storage Equipment		

65	(549) Miscellaneous Other Power Generation Expenses	2,398,819	914,364
66	(550) Rents	13,549	
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	288,373,918	629,164,801
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,500,855	1,820,214
70	(552) Maintenance of Structures	508,454	320,654
71	(553) Maintenance of Generating and Electric Plant	15,161,020	14,603,870
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,274,567	1,161,235
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	20,444,896	17,905,973
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	308,818,814	647,070,774
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	255,339,608	287,413,062
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	2,620,695	2,089,029
78	(557) Other Expenses	564,655	401,332
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	258,524,958	289,903,423
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	928,160,224	1,401,499,500
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,580,738	1,598,062
85	(561.1) Load Dispatch-Reliability	1,494,067	1,366,173
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	985,488	1,073,184
87	(561.3) Load Dispatch-Transmission Service and Scheduling	104,214	253,041
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	(13,691)	7,739
91	(561.7) Generation Interconnection Studies	(95,868)	(82,650)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,653,087	2,375,353
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	406,850	427,648
95	(564) Underground Lines Expenses	11,419	(114,709)
96	(565) Transmission of Electricity by Others	[a]437,534	[b]179,440
97	(566) Miscellaneous Transmission Expenses	7,320,054	7,048,009
98	(567) Rents	39,068	40,818

99	TOTAL Operation (Enter Total of Lines 83 thru 98)	14,922,960	14,172,108
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	424	204
102	(569) Maintenance of Structures	20,711	17,426
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment	36,310	29,485
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,038,499	2,329,163
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	8,982,606	6,914,377
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	81,624	83,414
111	TOTAL Maintenance (Total of Lines 101 thru 110)	11,160,174	9,374,069
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	26,083,134	23,546,177
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		

134	(580) Operation Supervision and Engineering	1,663,987	1,646,658
135	(581) Load Dispatching	1,802,424	1,835,263
136	(582) Station Expenses	2,247,014	2,073,611
137	(583) Overhead Line Expenses	965,890	1,797,075
138	(584) Underground Line Expenses	433,302	458,069
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	19,882	2,898
140	(586) Meter Expenses	1,643,070	1,380,598
141	(587) Customer Installations Expenses		208
142	(588) Miscellaneous Expenses	5,341,269	4,893,300
143	(589) Rents	2,852,558	2,734,517
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	16,969,396	16,822,197
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	164,200	160,241
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,296,459	1,483,042
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	40,862,639	41,890,878
150	(594) Maintenance of Underground Lines	2,512,454	2,236,544
151	(595) Maintenance of Line Transformers	701,929	170,801
152	(596) Maintenance of Street Lighting and Signal Systems	3,428,098	3,632,658
153	(597) Maintenance of Meters	1,253,511	964,783
154	(598) Maintenance of Miscellaneous Distribution Plant	2,297,891	2,240,307
155	TOTAL Maintenance (Total of Lines 146 thru 154)	52,517,181	52,779,254
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	69,486,577	69,601,451
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	417,350	477,726
160	(902) Meter Reading Expenses	835,150	1,173,703
161	(903) Customer Records and Collection Expenses	22,097,721	18,440,069
162	(904) Uncollectible Accounts	8,380,762	5,805,902
163	(905) Miscellaneous Customer Accounts Expenses	2,905,637	3,213,526
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	34,636,620	29,110,926
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		1,480

168	(908) Customer Assistance Expenses	28,721,827	38,553,372
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	28,721,827	38,554,852
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,454,695	1,371,444
176	(913) Advertising Expenses		1,653
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	1,454,695	1,373,097
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	75,145,518	76,054,878
182	(921) Office Supplies and Expenses	16,534,053	23,883,000
183	(Less) (922) Administrative Expenses Transferred-Credit	38,931,770	29,007,854
184	(923) Outside Services Employed	11,029,469	12,598,531
185	(924) Property Insurance	4,667,113	3,866,784
186	(925) Injuries and Damages	8,809,984	7,287,750
187	(926) Employee Pensions and Benefits	39,911,445	29,298,913
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,205,872	8,858,128
190	(929) (Less) Duplicate Charges-Cr.	11,635,745	9,308,458
191	(930.1) General Advertising Expenses	9,717	607,275
192	(930.2) Miscellaneous General Expenses	3,533,220	4,659,230
193	(931) Rents	9,302,995	9,431,647
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	126,581,871	138,229,824
195	Maintenance		
196	(935) Maintenance of General Plant	13,600,802	17,643,160
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	140,182,673	[g]155,872,984
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,228,725,750	1,719,558,987

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionOfElectricityByOthers

For the formula rate approved in the FERC proceeding listed on page 106, transmission of electricity by others will include $61 not included on this page. This is expense from a new energy trading platform that occurred in Q4 2022, but was not recorded until Q1 2023. This expense is reflective of 83 MWH.

(b) Concept: TransmissionOfElectricityByOthers

For the formula rate approved in the FERC proceeding listed on page 106, Transmission of Electricity By Others expenses will remove a credit of ($24,464) related to the correction of a duplicate expense from 2021.

For the formula rate approved in the FERC proceeding listed on page 106, Transmission of Electricity By Others will include $61 not included on this page. This is expense from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This expense is reflective of 83 MWH.

(c) Concept: AdministrativeAndGeneralExpenses

For the formula rate approved in the FERC proceeding listed on page 106, administrative and general expenses allocable to transmission will exclude $61,485 for Advance Metering Infrastructure program severance payments not related to transmission operations.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES: MegaWatt Hours Received (i)	POWER EXCHANGES: MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER: Demand Charges ($) (k)	COST/SETTLEMENT OF POWER: Energy Charges ($) (l)	COST/SETTLEMENT OF POWER: Other Charges ($) (m)	COST/SETTLEMENT OF POWER: Total (k+l+m) of Settlement ($) (n)
1	Santee Cooper (Kempson Bridge)	RQ	[(bo)] 0				1,115					127,653		127,653
2	Westrock	[(b)] OS	[(bp)] 0				5,700					165,757		165,757
3	Shaw Industries Inc	[(c)] OS	[(bq)] 0				6,297					194,234		194,234
4	International Paper	[(d)] OS	[(br)] 0				1,510					73,906		73,906
5	Misc Territorial Customers	[(e)] OS	[(bs)] Rate--PR1				816					23,608		23,608
6	Southeastern Power Administration	RQ	[(bt)] 1/2001,12/2002				51						[(fo)] 77,339	77,339
7	[(a)] South Carolina Generating Company, Inc	RQ	[(bu)] Schedule #1		469	386	1,993,411					185,924,878		185,924,878
8	Duke Energy Carolinas, LLC	[(f)] OS	[(bv)] Tariff #5				45,051					1,868,910		1,868,910

9	Constellation Energy Generation, LLC	(g) OS	(bw) Tariff #3				75,454					2,664,340		2,664,340
10	Macquarie Energy LLC	(h) OS	(bx) 0				54,413					2,614,582		2,614,582
11	North Carolina Municipal Power Agency No. 1	(i) OS	(by) 0				8,000					202,000		202,000
12	Rainbow Energy Marketing Corporation	(j) OS	(bz) Tariff #1				528					19,612		19,612
13	Southern Company Services, Inc.	(k) OS	(ca) Tariff #4				24,930					1,148,456		1,148,456
14	The Energy Authority, Inc	(l) OS	(cb) 12/1/2004				37,733					1,873,877		1,873,877
15	Duke Energy Carolinas, LLC -- Emergency	(m) OS	(cc) 0				8,277					288,233		288,233
16	Carolina Power Partners, LLC	(n) OS	(cd) 0				7,585					268,805		268,805
17	Barnwell Solar, LLC	(o) OS	(ce) 0				9,536					495,882		495,882
18	Cameron Solar II, LLC	(p) OS	(cf) 0				7,947					413,269		413,269
19	Haley Solar I, LLC	(q) OS	(cg) 0				9,203					478,563		478,563
20	Odyssey Solar, LLC	(r) OS	(ch) 0				17,479					908,890		908,890
21	Ridgeland Solar Farm I, LLC	(s) OS	(ci) 0				18,656					1,026,083		1,026,083
22	Saluda Solar II, LLC	(t) OS	(cj) 0				6,339					329,641		329,641
23	Saluda Solar, LLC	(u) OS	(ck) 0				12,150					631,802		631,802
24	TIG Sun Energy III, LLC	(v) OS	(cl) 0				850					82,244		82,244
25	TIG Sun Energy IV, LLC	(w) OS	(cm) 0				2,750					267,044		267,044
26	Cameron Solar, LLC	(x) OS	(cn) 0				43,564					2,134,643		2,134,643
27	Champion Solar, LLC	(y) OS	(co) 0				21,264					1,041,909		1,041,909
28	Estill Solar I, LLC	(z) OS	(cp) 0				34,715					1,701,012		1,701,012
29	Estill Solar II, LLC	(aa) OS	(cq) 0				18,230					893,282		893,282
30	Hampton Solar I, LLC	(ab) OS	(cr) 0				12,594					617,112		617,112
31	Hampton Solar II, LLC	(ac) OS	(cs) 0				40,110					1,965,402		1,965,402
32	Southern Current One, LLC	(ad) OS	(ct) 0				16,600					813,380		813,380
33	St. Matthews Solar, LLC	(ae) OS	(cu) 0				19,318					946,577		946,577
34	Swamp Fox Solar, LLC	(af) OS	(cv) 0				22,959					1,124,994		1,124,994
35	Moffett Solar 1, LLC	(ag) OS	(cw) 0	(ea) 0			138,044			(eu) 0	1,709,161	4,385,080		6,094,241
36	Seabrook Solar, LLC	(ah) OS	(cx) 0	(eb) 0			104,231			(ev) 0	583,023	2,831,671		3,414,694
37	Billing Credit Agreement (BCA) DER Solar Power Purchases	(ai) OS	(cy) 0				19,416					4,062,831		4,062,831

38	Blackville Solar II, LLC	[aj] OS	[cz] 0	[ec] 0			26,163			[ew] 0	174,728	651,740		826,468
39	Diamond Solar, LLC	[ak] OS	[da] 0	[ed] 0			9,987			[ex] 0	27,328	220,102		247,430
40	Edison Solar, LLC	[al] OS	[db] 0	[ee] 0			8,579			[ey] 0	44,990	225,829		270,819
41	Palmetto Plains Solar Project, LLC	[am] OS	[dc] 0	[ef] 0			129,917			[ez] 0	705,554	4,063,573		4,769,127
42	Peony Solar LLC	[an] OS	[dd] 0	[eg] 0			67,909			[fa] 0	393,762	1,901,328		2,295,090
43	Gaston Solar I, LLC	[ao] OS	[de] 0				20,204					989,995		989,995
44	Gaston Solar II, LLC	[ap] OS	[df] 0				9,825					463,717		463,717
45	Richardson Solar, LLC	[aq] OS	[dg] 0	[eh] 0			4,872			[fb] 0	35,129	138,773		173,902
46	Shaw Creek Solar, LLC	[ar] OS	[dh] 0	[ei] 0			170,651			[fc] 0	900,046	5,148,869		6,048,915
47	Nimitz Solar, LLC	[as] OS	[di] 0				14,670					1,300,230		1,300,230
48	Springfield Solar, LLC	[at] OS	[dj] 0				11,301					1,011,980		1,011,980
49	Curie Solar, LLC	[au] OS	[dk] 0				3,478					313,049		313,049
50	Parris Island	[av] OS	[dl] 0				1,375					39,460		39,460
51	Huntley Solar, LLC	[aw] OS	[dm] 0	[ej] 0			154,565			[fd] 0	843,550	4,804,053		5,647,603
52	Lily Solar, LLC	[ax] OS	[dn] 0	[ek] 0			158,455			[fe] 0	829,188	4,492,665		5,321,853
53	Midlands Solar, LLC	[ay] OS	[do] 0	[el] 0			139,436			[ff] 0	254,455	3,971,608		4,226,063
54	TWE Bowman Solar Project, LLC	[az] OS	[dp] 0	[em] 0			132,369			[fg] 0	226,600	3,846,419		4,073,019
55	Blackville Solar, LLC	[ba] OS	[dq] 0	[en] 0			15,621			[fh] 0	27,302	445,771		473,073
56	Denmark Solar, LLC	[bb] OS	[dr] 0	[eo] 0			13,058			[fi] 0	22,052	372,413		394,465
57	Yemassee Solar, LLC	[bc] OS	[ds] 0	[ep] 0			21,375			[fj] 0	37,023	610,386		647,409
58	Trask East Solar, LLC	[bd] OS	0	[eq] 0			23,325			[fk] 0	31,351	661,439		692,790
59	Beulah Solar, LLC	[be] OS	[dt] 0	[er] 0			148,215			[fl] 0	258,205	4,058,140		4,316,345
60	Georgia Power (Calhoun Falls)	[bf] OS	Schedule #793	0			47			0		1,522		1,522
61	Oglethorpe Power Corporation	[bg] OS	[du] 0	0			390			0		6,717		6,717
62	LG&E and KU Energy, LLC	[bh] OS	[dv] 0	0			1,974			0		83,299		83,299
63	Duke Energy Florida, LLC	[bi] OS	[dw] 0	0			6,598			0		161,697		161,697
64	Duke Energy Progress, LLC -- Emergency	[bj] OS	[dx] 0	0			639			0		23,020		23,020
65	Associated Electric Cooperative, Inc.	[bk] OS	[dy] 0	0			242			0		7,028		7,028
66	Eastover Solar, LLC	[bl] OS					87,060					[fm] (1,138,015)		(1,138,015)
67	North Carolina Electric Membership Corporation	[bm] OS					1,793					59,095		59,095

68	Other	(bn) OS	(dz) 0	(es)0						(fm)0				
69	Adjustments						(et)76,091						(fp) (15,387,241)	(15,387,241)
15	TOTAL						4,307,010	0	0	0	7,103,447	263,546,064	(15,309,902)	255,339,609

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliated Company

(b) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

(c) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

(d) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

(e) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

(f) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the Edison Electric Institute Inc.(EEI) Master Purchase and Sale Agreement.

(g) Concept: StatisticalClassificationCode

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(bn) Concept: StatisticalClassificationCode
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
(bo) Concept: RateScheduleTariffNumber
Contract for electric service dated 1/1/1996.
(bp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-16-E, Order No. 2019-36.
(bq) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-344-E, Order No. 2019-806.
(br) Concept: RateScheduleTariffNumber
Contract for electric service dated 5/1/1984.
(bs) Concept: RateScheduleTariffNumber
Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.
(bt) Concept: RateScheduleTariffNumber
Docket Nos. ER01-1043-000 and ER03-237-000.
(bu) Concept: RateScheduleTariffNumber
FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format - Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.
(bv) Concept: RateScheduleTariffNumber
Tariff No. 5, Docket No. ER12-2322.
(bw) Concept: RateScheduleTariffNumber
FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.
(bx) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 9/1/2002.
(by) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 6/1/2003.
(bz) Concept: RateScheduleTariffNumber
Tariff No. 1, Docket No. ER10-2778
(ca) Concept: RateScheduleTariffNumber
Tariff No. 4, Docket No. ER10-2881.
(cb) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.
(cc) Concept: RateScheduleTariffNumber
FERC Electric Rate Schedule No. 42.
(cd) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 8/20/2021.
(ce) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-175-E, Order Nos. 2016-368, 2017-311 and 2017-546.
(cf) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-177-E, Order Nos. 2016-369, 2017-312 and 2017-547.

(cg) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-178-E, Order Nos. 2016-370 and 2017-315.
(ch) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-181-E, Order Nos. 2016-372, 2017-316 and 2017-549.
(ci) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-278-E, Order No. 2016-548.
(cj) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-174-E, Order Nos. 2016-367, 2017-317 and 2017-552.
(ck) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-182-E, Order Nos. 2016-373 and 2017-326.
(cl) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-363-E, Order No. 2015-788.
(cm) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-166-E, Order No. 2017-373.
(cn) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-167-E, Order No. 2016-341, 2017-309, and 2017-310.
(co) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-171-E, Order No. 2016-364 and 2017-313.
(cp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-173-E, Order No. 2016-366, 2017-285, and 2017-286.
(cq) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-378-E, Order No. 2015-812 and 2017-289.
(cr) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-380-E, Order No. 2015-814, 2016-324, 2017-293, and 2017-548.
(cs) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-169-E, Order No. 2016-343, 2017-287, and 2017-288.
(ct) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-379-E, Order No. 2015-813, 2017-318, and 2017-551.
(cu) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-168-E, Order No. 2016-342, 2017-319, and 2017-550.
(cv) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-179-E, Order No. 2016-371 and 2017-320.
(cw) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-100-E, Order No. 2016-200.
(cx) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order no. 2017-424.
(cy) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-54-E, Order Nos. 2015-512 and 2015-765.
(cz) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-181-E, Order No. 2017-417.
(da) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-182-E, Order No. 2017-418.
(db) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-183-E, Order No. 2017-419.

(dc) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-160-E, Order No. 2017-372.
(dd) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(de) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-172-E, Order Nos. 2016-365 and 2017-290.
(df) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-170-E, Order Nos. 2016-344 and 2017-314.
(dg) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-186-E, Order No. 2017-422.
(dh) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-143-E, Order No. 2017-321.
(di) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(dj) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(dk) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(dl) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-344-E, Order No. 2019-806.
(dm) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dn) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(do) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dq) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(dr) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(ds) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(dt) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-160-E, Order No. 2017-372.
(du) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 9/1/2004.
(dv) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2003.
(dw) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2
(dx) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule No. 29.
(dy) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 3/30/2023.
(dz) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424
(ea) Concept: AverageMonthlyBillingDemand
Moffet Solar 1, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of June, July and August as specified in the contract.
(eb) Concept: AverageMonthlyBillingDemand
Seabrook Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ec) Concept: AverageMonthlyBillingDemand
Blackville Solar II, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ed) Concept: AverageMonthlyBillingDemand
Diamond Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ee) Concept: AverageMonthlyBillingDemand
Edison Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ef) Concept: AverageMonthlyBillingDemand
Palmetto Plains Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(eg) Concept: AverageMonthlyBillingDemand
Peony Solar LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(eh) Concept: AverageMonthlyBillingDemand
Richardson Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ei) Concept: AverageMonthlyBillingDemand
Shaw Creek Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ej) Concept: AverageMonthlyBillingDemand
Huntley Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ek) Concept: AverageMonthlyBillingDemand
Lily Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(el) Concept: AverageMonthlyBillingDemand
Midlands Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(em) Concept: AverageMonthlyBillingDemand
TWE Bowman Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(en) Concept: AverageMonthlyBillingDemand
Blackville Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(eo) Concept: AverageMonthlyBillingDemand
Denmark Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ep) Concept: AverageMonthlyBillingDemand
Yamassee Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(eq) Concept: AverageMonthlyBillingDemand
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(er) Concept: AverageMonthlyBillingDemand
Beulah Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(es) Concept: AverageMonthlyBillingDemand
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(et) Concept: MegawattHoursPurchasedOtherThanStorage

Includes 76,091 megawatt hours of Net Energy Metering purchases from customers which are not classified as purchased power but have been shown on this schedule in order for total megawatt hours purchased reported on this schedule to tie to page 401a, line 10 column b in accordance with the Taxonomy provided by FERC.

(eu) Concept: EnergyDeliveredThroughPowerExchanges

Moffet Solar 1, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of June, July and August as specified in the contract.

(ev) Concept: EnergyDeliveredThroughPowerExchanges

Seabrook Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ew) Concept: EnergyDeliveredThroughPowerExchanges

Blackville Solar II, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ex) Concept: EnergyDeliveredThroughPowerExchanges

Diamond Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ey) Concept: EnergyDeliveredThroughPowerExchanges

Edison Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ez) Concept: EnergyDeliveredThroughPowerExchanges

Palmetto Plains Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fa) Concept: EnergyDeliveredThroughPowerExchanges

Peony Solar LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fb) Concept: EnergyDeliveredThroughPowerExchanges

Richardson Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fc) Concept: EnergyDeliveredThroughPowerExchanges

Shaw Creek Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fd) Concept: EnergyDeliveredThroughPowerExchanges

Huntley Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fe) Concept: EnergyDeliveredThroughPowerExchanges

Lily Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ff) Concept: EnergyDeliveredThroughPowerExchanges

Midlands Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fg) Concept: EnergyDeliveredThroughPowerExchanges

TWE Bowman Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fh) Concept: EnergyDeliveredThroughPowerExchanges

Blackville Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fi) Concept: EnergyDeliveredThroughPowerExchanges

Denmark Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fj) Concept: EnergyDeliveredThroughPowerExchanges

Yamassee Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fk) Concept: EnergyDeliveredThroughPowerExchanges

Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fl) Concept: EnergyDeliveredThroughPowerExchanges

Beulah Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fm) Concept: EnergyDeliveredThroughPowerExchanges

Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fn) Concept: EnergyChargesOfPurchasedPower

Eastover Solar total includes $2,979,328 of liquidated damages related to COD delays.

(fo) Concept: OtherChargesOfPurchasedPower

Energy Charges represent a barter arrangement for transmission ancillary services 1,2,5 and 6.

(fp) Concept: OtherChargesOfPurchasedPower
Reflects deferral of purchased power of $1,222,791 per SCPSC Docket No. 2009-489-E, 2012-218-E, 2017-210-E, 2019-159-E and 2020-125-E.
Reflects amortization of previously deferred purchased power of $282,659 per SCPSC Docket No. 2009-489-E.
Reflects the deferral of capacity purchases per SCPSC Docket No. 2020-125-E of $711,504.
Reflects Boeing Green Premium $57,973.
Reflects the deferral of purchase power of ($11,321,508) pursuant to SCPSC Docket No. 2015-54-E, under the Company's Distributed Energy Resources (DER) program.
Reflects the Solar Project Penalties of ($4,533).
Reflects Boeing Green Premium ($237,196)
Reflects True up of December 2022 Emergency Purchases in January 2023 ($4,746,567) -- (Duke Progress ($4,340,939.50), Duke Carolinas ($3,127,713.87), Southern Company $2,722,086)
Reflects amortization of EDIT from GENCO per SCPSC Docket No. 2020-125-E of ($1,352,364).

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY: Megawatt Hours Received (i)	TRANSFER OF ENERGY: Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS: Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Southern Company Services, Inc.	Georgia Power Company	Duke Energy Carolinas, LLC	NF	S8,S1,S2	SOCO	DUK	[(h)] 0	[(y)] 100	[(aw)] 94	369		[(cj)] 27	396
2	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF	S8,S1,S2	DUK	SOCO	[(i)] 0	[(z)] 745	[(ax)] 726	4,505		[(ck)] 256	4,761
3	Progress Energy Carolinas, LLC	Georgia Power Company	Progress Energy Carolinas, LLC	NF	S8,S1,S2	SOCO	CPLE	[(j)] 0	[(aa)] 0	[(ay)] 0	108		[(cl)] 7	115
4	Macquarie Energy LLC	Georgia Power Company	Progress Energy Carolinas, LLC	SFP	S7,S1,S2	SOCO	CPLE	131	[(ab)] 3,061	[(az)] 3,000	14,851		[(cm)] 956	15,807
5	The Energy Authority	Dominion Energy South Carolina, Inc.	Progress Energy Carolinas, LLC	NF	S8,S1,S2	SCEG	SC	[(k)] 0	[(ac)] 0	[(ba)] 0	257		[(cn)] 18	275
6	The Energy Authority	Georgia Power Company	South Carolina Public Service Authority	NF	S8,S1,S2	SOCO	SC	[(l)] 0	[(ad)] 101	[(bb)] 98	1,562		[(co)] 98	1,660
7	Associated Electric Cooperative, Inc.	Dominion Energy South Carolina, Inc.	Associated Electric Cooperative, Inc.	NF	S8,S1,S2	SCEG	APM	[(m)] 0	[(ae)] 91	[(bc)] 91	[(bu)] 56		[(cp)] 0	56
8	Duke Energy Carolinas, LLC	Dominion Energy South Carolina, Inc.	Duke Energy Carolinas, LLC	NF	S8,S1,S2	SCEG	DUK	[(n)] 0	[(af)] 4,325	[(bd)] 4,325	[(bv)] 2,957		[(cq)] 0	2,957
9	Southern Company Services, Inc.	Dominion Energy South Carolina, Inc.	Georgia Power Company	NF	S8,S1,S2	SCEG	SOCO	[(o)] 0	[(ag)] 4,095	[(be)] 4,095	[(bw)] 3,169		[(cr)] 0	3,169
10	The Energy Authority	Dominion Energy South Carolina, Inc.	Jacksonville Electric Authority	NF	S8,S1,S2	SCEG	JEA	[(p)] 0	[(ah)] 504	[(bf)] 504	[(bx)] 417		[(cs)] 0	417
11	The Energy Authority	Dominion Energy South Carolina, Inc.	Municipal Electric Authority of Georgia	NF	S8,S1,S2	SCEG	MEAG	[(q)] 0	[(ai)] 139	[(bg)] 139	[(by)] 116		[(ct)] 0	116
12	The Energy Authority	Dominion Energy South Carolina, Inc.	Gainesville Regional Utilities	NF	S8,S1,S2	SCEG	GVL	[(r)] 0	[(aj)] 202	[(bh)] 202	[(bz)] 175		[(cu)] 0	175
13	Louisville Gas & Electric Company/Kentucky Utilities Company	Dominion Energy South Carolina, Inc.	Louisville Gas & Electric Company/Kentucky Utilities Company	NF	S8,S1,S2	SCEG	LGE	[(s)] 0	[(ak)] 400	[(bi)] 400	[(ca)] 470		[(cv)] 0	470
14	Oglethorpe Power Corporation	Dominion Energy South Carolina, Inc.	Oglethorpe Power Corporation	NF	S8,S1,S2	SCEG	OPC	[(t)] 0	[(al)] 25	[(bj)] 25	[(cb)] 19		[(cw)] 0	19
15	North Carolina Electric Membership Corporation	Dominion Energy South Carolina, Inc.	North Carolina Electric Membership Corporation	NF	S8,S1,S2	SCEG	NCEMC	[(u)] 0	[(am)] 2	[(bk)] 2	[(cc)] 2		[(cx)] 0	2
16	Tennessee Valley Authority	Dominion Energy South Carolina, Inc.	Tennessee Valley Authority	NF	S8,S1,S2	SCEG	TVA	[(v)] 0	[(an)] 340	[(bl)] 340	[(cd)] 265		[(cy)] 0	265
17	Tampa Electric Company	Dominion Energy South Carolina, Inc.	Tampa Electric Company	NF	S8,S1,S2	SCEG	TECM	[(w)] 0	[(ao)] 478	[(bm)] 478	[(ce)] 373		[(cz)] 0	373
18	Duke Florida Energy, LLC	Dominion Energy South Carolina, Inc.	Duke Florida Energy, LLC	NF	S8,S1,S2	SCEG	FPCM	[(x)] 0	[(ap)] 846	[(bn)] 846	[(cf)] 584		[(da)] 0	584

19	South Carolina Public Service Authority	South Carolina Public Service Authority	Central Electric Power Co-op	FNO	[b] Attach H			753	[aq] 324,987	[bo] 315,522	3,920,174	[cg] 39,260	[db] 125,421	[dh] 4,084,855
20	Southeastern Power Administration	Southeastern Power Administration	[a] 0	FNO	[c] Attach H			240	[ar] 37,509	[bp] 36,296	1,202,547		[dc] 77,339	[di] 1,279,886
21	City of Orangeburg	Dominion Energy South Carolina, Inc.	City of Orangeburg	FNO	[d] Attach H			1,436	[as] 753,497	[bq] 731,550	7,325,875		[dd] 537,997	[dj] 7,863,872
22	Town of Winnsboro	Dominion Energy South Carolina, Inc.	Town of Winnsboro	FNO	[e] Attach H			112	[at] 57,204	[br] 56,083	581,025		[de] 42,673	[dk] 623,698
23	Central Electric Power Co-op	South Carolina Public Service Authority	Central Electric Power Co-op	FNO	[f] Attach H			161	[au] 62,999	[bs] 61,763	846,659	[ch] 10,665	[df] 27,085	[dl] 884,409
24	McCormick Commission of Public Works	Duke Energy Carolinas, LLC	McCormick Commission of Public Works	FNO	[g] Attach H			40	[av] 18,493	[bt] 18,130	210,072	[ci] 95,325	[dg] 15,446	[dm] 320,843
35	TOTAL							2,873	[dn] 1,270,143	[do] 1,234,709	[dp] 14,116,607	145,250	827,323	[dq] 15,089,180

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

South Carolina Public Service Authority, Little River Electric Cooperative, McCormick CPW, City of Orangeburg and Town of Winnsboro.

(b) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1 S2 and S4 of Tariff.

(c) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.

(d) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

(e) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

(f) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1 S2 and S4 of Tariff.

(g) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S4, S5 and S6 of Tariff.

(h) Concept: BillingDemand

Non-firm hourly billing demand of 105.

(i) Concept: BillingDemand

Non-firm hourly billing demand of 765.

(j) Concept: BillingDemand

Non-firm hourly billing demand of 21.

(k) Concept: BillingDemand

Non-firm hourly billing demand of 211.

(l) Concept: BillingDemand

Non-firm hourly billing demand of 73.

(m) Concept: BillingDemand

Non-firm hourly billing demand of 86.

(n) Concept: BillingDemand

Non-firm hourly billing demand of 4322.

(o) Concept: BillingDemand

Non-firm hourly billing demand of 3,467.

(p) Concept: BillingDemand

Non-firm hourly billing demand of 504.

(q) Concept: BillingDemand

Non-firm hourly billing demand of 108.

(r) Concept: BillingDemand

Non-firm hourly billing demand of 202.

(s) Concept: BillingDemand

Non-firm hourly billing demand of 314.

(t) Concept: BillingDemand
Non-firm hourly billing demand of 25.
(u) Concept: BillingDemand
Non-firm hourly billing demand of 2.
(v) Concept: BillingDemand
Non-firm hourly billing demand of 330.
(w) Concept: BillingDemand
Non-firm hourly billing demand of 478.
(x) Concept: BillingDemand
Non-firm hourly billing demand of 846.
(y) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(z) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aa) Concept: TransmissionOfElectricityForOthersEnergyReceived
Customer reserved transmission service, but did not schedule service.
(ab) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ac) Concept: TransmissionOfElectricityForOthersEnergyReceived
Customer reserved transmission service, but did not schedule service.
(ad) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ae) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(af) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ag) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ah) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ai) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aj) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ak) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(al) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(am) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(an) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ao) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.

(ap) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aq) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ar) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(as) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(at) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(au) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(av) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aw) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities
(ax) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ay) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Customer reserved transmission service, but did not schedule service.
(az) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ba) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Customer reserved transmission service, but did not schedule service.
(bb) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bc) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bd) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(be) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bf) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bg) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bh) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bi) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bj) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(bk) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bl) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bm) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bn) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bo) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bp) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bq) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(br) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bs) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bt) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(bu) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(bv) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(bw) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(bx) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(by) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(bz) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(ca) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cb) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cc) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cd) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(ce) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cf) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cg) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers

Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

(ch) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers

Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

(ci) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers

Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

(cj) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges.

(ck) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges.

(cl) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges

(cm) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges.

(cn) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges.

(co) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges.

(cp) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cr) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cs) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(ct) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cu) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cv) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cx) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cy) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(cz) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(da) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

NFEETS transaction. There are no Base or Ancillary Charges for NFEETS transactions. The Demand Charge is only payment for losses per the Tariff.

(db) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Sum of Ancillary Service 1 and 2 charges

(dc) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1, 2, 5 and 6 charges.
(dd) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1, 2, 3, 5 and 6 charges.
(de) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1, 2, 3, 5 and 6 charges.
(df) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges
(dg) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1, 2, 3, 5 and 6 charges.
(dh) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(di) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(dj) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(dk) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(dl) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(dm) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(dn) Concept: TransmissionOfElectricityForOthersEnergyReceived
These amounts include $732 in revenue from a new energy platform that occurred in Q4 2022 but was not booked until Q1 2023. This revenue is reflective of 763 MWH.
(do) Concept: TransmissionOfElectricityForOthersEnergyDelivered
These amounts include $732 in revenue from a new energy platform that occurred in Q4 2022 but was not booked until Q1 2023. This revenue is reflective of 763 MWH.
(dp) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers
These amounts include $732 in revenue from a new energy platform that occurred in Q4 2022 but was not booked until Q1 2023. This revenue is reflective of 763 MWH.
(dq) Concept: RevenuesFromTransmissionOfElectricityForOthers
These amounts include $732 in revenue from a new energy platform that occurred in Q4 2022 but was not booked until Q1 2023. This revenue is reflective of 763 MWH.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
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12					
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49					
40	TOTAL				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	5,596	5,534	25,106	10,891	[(a)] 18,454	54,451
2	Duke Energy Carolinas	NF					[(b)] 500	500
3	Duke Energy Florida	NF					[(c)] 41	41
4	PJM Settlement, Inc.	NF	400	400	804		[(d)] 69,588	70,392
5	Central Electric Power Cooperative, Inc.	OS					[(e)] 131,557	131,557
6	Tennessee Valley Authority	NF					[(f)] 211	211
7	Municipal Electric Authority of Georgia	NF					[(g)] 756	756
8	Southern Company Services, Inc.	NF					[(h)] 1,247	1,247
9	Santee Cooper	NF					[(i)] 7	7
10	Georgia Transmission Corp.	NF					[(j)] 28	28
11	Santee Cooper	SFP	25,726	25,009	165,317		[(k)] 13,014	178,331
12	Duke Energy Progress	NF					[(l)] 13	13
13	Adjustments							
	TOTAL		31,722	30,943	191,227	10,891	235,416	[(m)] 437,534

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	592
Reactive Supply and Voltage Control		2,402
Regulation and Frequency Response		456
Operating Reserve - Spinning		978
Operating Reserve - Supplement		978
Other - Direct Assignment Charges		13,048
Total	$	18,454

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		500
Total	$	500

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		41
Total	$	41

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	150
Reactive Supply and Voltage Control		309
Operating Reserve -- Spinning		7,131
Black Start Service		54
Day-Ahead Load Response Charge Allocation		32
Market Monitoring Unit (MMU) Funding		3
PJM Settlement, Inc.		778
Real-Time Load Response Charge Allocation		7
FERC Annual Recovery		34
Emergency Energy		(8,727)
Balancing Transmission Congestion		2,763
Transmission Losses		(113)
Pre-Emergency and Emergency Load Response		68,507
Reversal of Estimated Transmission for December 2022		(1,340)
Total	$	69,588

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Other - Sewee/Commonwealth Transmission Facility Charges	$	131,557
Total	$	131,557

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		211
Total	$	211

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		756
Total	$	756

(h) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		1,247
Total	$	1,247

(i) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		7
Total	$	7

(j) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		28
Total	$	28

(k) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	6,040
Reactive Supply and Voltage Control		6,974
Total	$	13,014

(l) Concept: OtherChargesTransmissionOfElectricityByOthers

Loss related to SEEM trading platform activity		13
Total	$	13

(m) Concept: ChargesForTransmissionOfElectricityByOthers

83 mwh totaling $61 of Transmission provided by others is included in the totals on this page. This is expense from a new energy trading platform that occurred in Q4 2022, was booked in Q1 2023.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	298,318
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	907,873
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Transportation and Other Power Operating equipment	
7	Environmental Fees	24,416
8	Financing Fees	185,517
9	DES Billing - Amortization	927,368
10	DES Billing - Depreciation	61,042
11	DES Billing - Misc. expenses	770
12	Research & Development Grant Amortization	100,000
13	Misc Expense	1,027,916
46	TOTAL	3,533,220

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			4,551,556		4,551,556
2	Steam Production Plant	64,599,683				64,599,683
3	Nuclear Production Plant	27,078,643				27,078,643
4	Hydraulic Production Plant-Conventional	2,904,610				2,904,610
5	Hydraulic Production Plant-Pumped Storage	2,705,204				2,705,204
6	Other Production Plant	22,090,177				22,090,177
7	Transmission Plant	52,558,084				52,558,084
8	Distribution Plant	104,070,679				104,070,679
9	Regional Transmission and Market Operation					
10	General Plant	4,705,436				4,705,436
11	Common Plant-Electric	6,588,727		4,921,263		11,509,990
12	TOTAL	287,301,243		9,472,819		296,774,062

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of Amortization of Parr Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with VC Summer Nuclear Station. The charges were based on plant balances of Parr -$7,272,676, Stevens Creek- $2,268,402, Neal Shoals-$1,507,162. The associated costs of relicensing the VC Summer Nuclear Plant through 2062 is $23,320,101. Data processing software costs of $87,143,623 are being amortized over the expected life of the software application. Common Plant (Account 404) represents the amortization of data processing software of $152,277,855 over the expected life of the software application.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	See Footnote [a]						
13	Steam Production:						
14	Urquhart - 311	19,251	80 years	(13)%	1.99%	R2	15 years, 9 months, 18 days
15	Urquhart - 312	27,275	41 years	(13)%	5.59%	S0	13 years, 4 months, 24 days
16	Urquhart - 314	62,480	52 years	(13)%	4.03%	S0	15 years, 4 months, 24 days
17	Urquhart - 315	19,429	65 years	(13)%	5.29%	R2	15 years, 10 months, 25 days
18	Urquhart - 316	7,063	41 years	(13)%	4.99%	R0.5	14 years, 10 months, 25 days

19	Total Urquhart	135,498					
20	McMeekin - 311	19,832	80 years	(16)%	2.61%	R2	18 years, 8 months, 12 days
21	McMeekin - 312	111,488	41 years	(16)%	3.77%	S0	16 years, 3 months, 19 days
22	McMeekin - 314	47,102	52 years	(16)%	3.19%	S0	17 years, 7 months, 6 days
23	McMeekin - 315	12,101	65 years	(16)%	2.88%	R2	18 years, 10 months, 25 days
24	McMeekin - 316	7,824	41 years	(16)%	3.99%	R0.5	16 years, 7 months, 6 days
25	Total McMeekin	198,347					
26	Cope - 311	82,949	80 years	(17)%	1.55%	R2	46 years, 1 month, 6 days
27	Cope - 312	329,776	41 years	(17)%	2.34%	S0	28 years, 1 month, 6 days
28	Cope - 312 SCR	71,322	41 years	(17)%	2.34%	S0	28 years, 1 month, 6 days
29	Cope - 314	91,190	52 years	(17)%	1.62%	S0	33 years, 7 months, 6 days
30	Cope - 315	24,363	65 years	(17)%	1.49%	R2	40 years, 10 months, 25 days
31	Cope - 316	12,681	41 years	(17)%	2.59%	R0.5	31 years, 3 months, 19 days
32	Cope - 316 SCR	618	41 years	(17)%	2.59%	R0.5	31 years, 3 months, 19 days
33	Total Cope	612,899					
34	Columbia Energy Center - 311 Initial Investment	[(b)]4,625					
35	Columbia Energy Center - 312 Initial Investment	[(c)]23,475					
36	Columbia Energy Center - 314 Initial Investment	[(d)]68,486					
37	Columbia Energy Center - 316 Initial Investment	[(e)]1,719					
38	Columbia Energy Center - 311	29	80 years	(15)%	0.8%	R2	34 years, 8 months, 12 days
39	Columbia Energy Center - 312	1,687	41 years	(15)%	0.19%	S0	29 years, 10 months, 25 days
40	Columbia Energy Center - 314	2,882	52 years	(15)%	0.5%	S0	31 years, 9 months, 18 days
41	Columbia Energy Center - 315	12	65 years	(15)%	0.88%	R2	34 years, 3 months, 19 days
42	Columbia Energy Center - 316	96	41 years	(15)%	1.58%	R0.5	29 years, 1 month, 6 days
43	Total Columbia Energy Center	103,011					
44	Jasper - 311		80 years	(13)%	4.53%	R2	24 years, 10 months, 25 days
45	Jasper - 312	509	41 years	(13)%	4.68%	S0	22 years, 7 months, 6 days
46	Jasper - 314	100,396	52 years	(13)%	3.87%	S0	22 years, 2 months, 12 days
47	Jasper - 315	7,221	65 years	(13)%	3.63%	R2	24 years, 3 months, 19 days
48	Jasper - 316	524	41 years	(13)%	4.48%	R0.5	21 years, 9 months, 18 days
49	Total Jasper	108,650					
50	Central Lab - 311	3,515	80 years	(9)%	1.59%	R2	18 years, 9 months, 18 days
51	Central Lab - 315	59	65 years	(9)%	0.89%	R2.5	17 years, 9 months, 18 days
52	Central Lab - 316	2,872	41 years	(9)%	4.01%	R0.5	17 years, 1 month, 6 days
53	Total Central Lab	6,446					

54	Wateree - 311	69,238	80 years	(17)%	3.26%	R2	25 years, 6 months
55	Wateree - 311 Scrubber	81,557	80 years	(17)%	3.26%	R2	25 years, 6 months
56	Wateree - 312	401,094	41 years	(17)%	3.59%	S0	21 years, 4 months, 24 days
57	Wateree - 312 Scrubber	224,050	41 years	(17)%	3.59%	S0	21 years, 4 months, 24 days
58	Wateree - 314	141,052	52 years	(17)%	2.87%	S0.5	22 years, 7 months, 6 days
59	Wateree - 315	31,001	65 years	(17)%	3.27%	R2	24 years, 8 months, 12 days
60	Wateree - 316	10,830	41 years	(17)%	4.16%	R0.5	21 years, 7 months, 6 days
61	Total Wateree	958,822					
62	Nuclear Production:						
63	V.C. Summer -321	393,933	80 years	(3)%	1.32%	R2.5	39 years, 3 months, 19 days
64	V.C. Summer -322	561,036	60 years	(5)%	1.71%	R2.5	35 years, 3 months, 19 days
65	V.C. Summer -323	110,011	45 years	(5)%	2.74%	S1	27 years, 1 month, 6 days
66	V.C. Summer -324	118,863	55 years	(1)%	1.31%	R3	29 years, 2 months, 12 days
67	V.C. Summer -325	198,207	30 years	(3)%	3.77%	R2.5	19 years, 2 months, 12 days
68	V.C. Summer -325.5	10,973	30 years		3.5%	R2.5	28 years, 2 months, 12 days
69	Total V.C. Summer	1,393,023					
70	Hydro Production - Conventional:						
71	Neal Shoals - 331	838	110 years	(19)%	1.64%	R2	35 years, 1 month, 6 days
72	Neal Shoals - 332	5,269	125 years	(19)%	2.64%	R2.5	34 years, 7 months, 6 days
73	Neal Shoals - 333	3,954	90 years	(19)%	2.35%	S0.5	33 years, 4 months, 24 days
74	Neal Shoals - 334	511	50 years	(19)%	2.49%	O1	28 years, 10 months, 25 days
75	Neal Shoals - 335	386	65 years	(19)%	2.55%	R1.5	32 years, 9 months, 18 days
76	Neal Shoals - 336	3	75 years	(19)%	1.18%	R4	33 years, 6 months
77	Total Neal Shoals	10,961					
78	Parr - 331	1,887	110 years	(19)%	2.33%	R2	42 years, 9 months, 18 days
79	Parr - 332	5,884	125 years	(19)%	1.92%	R2.5	42 years, 1 month, 6 days
80	Parr - 333	2,834	90 years	(19)%	2.33%	S0.5	40 years, 6 months
81	Parr - 334	2,025	50 years	(19)%	2.25%	O1	33 years, 3 months, 19 days
82	Parr - 335	828	65 years	(19)%	2.21%	R1.5	39 years, 6 months
83	Parr - 336	124	75 years	(19)%	1.21%	R4	43 years, 7 months, 6 days
84	Total Parr	13,582					
85	Stevens Ck - 331	3,175	110 years	(18)%	1.13%	R2	55 years, 6 months
86	Stevens Ck - 332	8,453	125 years	(18)%	0.92%	R2.5	57 years, 10 months, 25 days
87	Stevens Ck - 333	3,213	90 years	(18)%	1.43%	S0.5	51 years, 1 month, 6 days
88	Stevens Ck - 334	928	50 years	(18)%	1.89%	O1	36 years, 6 months
89	Stevens Ck - 335	1,530	65 years	(18)%	1.68%	R1.5	48 years

90	Stevens Ck - 336	129	75 years	(18)%	1.33%	R4	54 years, 6 months
91	Total Stevens Ck	17,428					
92	Saluda - 331	8,143	110 years	(4)%	1.19%	R2	56 years, 4 months, 24 days
93	Saluda - 332	21,738	125 years	(4)%	0.66%	R2.5	52 years, 9 months, 18 days
94	Saluda - 332.5 (Backup Dam)	332,840	125 years	(4)%	0.39%	R2.5	60 years, 7 months, 6 days
95	Saluda - 333	11,705	90 years	(4)%	1.07%	S0	48 years
96	Saluda - 334	9,953	50 years	(4)%	2.43%	O1	39 years, 8 months, 12 days
97	Saluda - 335	3,455	65 years	(4)%	1.74%	R1.5	48 years, 6 months
98	Saluda - 336	234	75 years	(4)%	0.88%	R4	44 years, 7 months, 6 days
99	Total Saluda	388,068					
100	Hydro Production - Pumped Storage:						
101	Fairfield - 331	37,740	110 years	(19)%	0.94%	R2	74 years
102	Fairfield - 332	74,835	125 years	(19)%	0.86%	R2.5	82 years, 6 months
103	Fairfield - 333	68,399	90 years	(19)%	1.33%	S0	64 years, 8 months, 12 days
104	Fairfield - 334	21,811	50 years	(19)%	2.53%	O1	45 years, 10 months, 25 days
105	Fairfield - 335	7,102	65 years	(19)%	2.62%	R1.5	43 years, 7 months, 6 days
106	Fairfield - 336	1,328	75 years	(19)%	1.6%	R4	35 years, 9 months, 18 days
107	Total Fairfield	211,215					
108	Other Production - Gas Turbine Units:						
109	Hardeeville - 341	58	55 years	(10)%	0.75%	R2.5	1 year
110	Hardeeville - 342	534	55 years	(10)%	(9.34)%	R2	1 year
111	Hardeeville - 343	799	35 years	(10)%	(4.65)%	R2	1 year
112	Hardeeville - 344	1,863	65 years	(10)%	(9.61)%	S1	1 year
113	Hardeeville - 345	283	40 years	(10)%	(8.77)%	S2	1 year
114	Hardeeville - 346	74	42 years	(10)%	11.4%	R1	1 year
115	Total Hardeeville	3,611					
116	Coit - 341	147	55 years	(10)%	2.27%	R2.5	10 years, 3 months, 19 days
117	Coit - 342	605	55 years	(10)%	2.1%	R2	10 years, 2 months, 12 days
118	Coit - 343	1,380	35 years	(10)%	3.62%	R2	9 years, 10 months, 25 days
119	Coit - 344	3,490	65 years	(10)%	0.61%	S1	9 years, 6 months
120	Coit - 345	622	40 years	(10)%	3.92%	S2	10 years, 2 months, 12 days
121	Coit - 346	172	42 years	(10)%	2.8%	R1	9 years, 10 months, 25 days
122	Total Coit	6,416					
123	Parr - 341	890	55 years	(10)%	2.05%	R2.5	20 years, 3 months, 19 days
124	Parr - 342	565	55 years	(10)%	1.14%	R2	17 years, 8 months, 12 days
125	Parr - 343	4,519	35 years	(10)%	3.82%	R2	18 years, 9 months, 18 days

126	Parr - 344	3,371	65 years	(10)%	2.29%	S1	18 years, 8 months, 12 days
127	Parr - 345	1,606	40 years	(10)%	2.11%	S2	18 years, 10 months, 25 days
128	Parr - 345.5	1,833	40 years	(10)%	4.78%	S2	21 years
129	Parr - 346	270	42 years	(10)%	2.83%	R1	19 years
130	Total Parr	11,221					
131	Bushy Park - 341	654	55 years	(11)%	11.33%	R2.5	6 years, 4 months, 24 days
132	Bushy Park - 342	400	55 years	(11)%	3.7%	R2	6 years, 4 months, 24 days
133	Bushy Park - 343	6,474	35 years	(11)%	4.72%	R2	6 years, 2 months, 12 days
134	Bushy Park - 344	65	65 years	(11)%	4.52%	S1	6 years, 3 months, 19 days
135	Bushy Park - 345	418	40 years	(11)%	11.86%	S2	6 years, 4 months, 24 days
136	Bushy Park - 346	121	42 years	(11)%	8.45%	R1	6 years, 3 months, 19 days
137	Total Bushy Park	8,132					
138	Hagood - 341	3,465	55 years	(11)%	1.91%	R2.5	20 years, 2 months, 12 days
139	Hagood - 342	913	55 years	(11)%	1.44%	R2	20 years, 3 months, 19 days
140	Hagood - 343	24,537	35 years	(11)%	1.22%	R2	14 years, 4 months, 24 days
141	Hagood - 344	5,801	65 years	(11)%	1.45%	S1	20 years, 1 month, 6 days
142	Hagood - 345	3,232	40 years	(11)%	2.25%	S2	17 years, 1 month, 6 days
143	Hagood - 345.5	13	40 years	(11)%	5.03%	S2	22 years, 1 month, 6 days
144	Hagood - 346	469	42 years	(11)%	4.3%	R1	19 years, 9 months, 18 days
145	Total Hagood	38,430					
146	Jasper - 341	28,278	55 years	(12)%	3.16%	R2.5	23 years, 10 months, 25 days
147	Jasper - 342	31	55 years	(12)%	4.45%	R2	24 years, 4 months, 24 days
148	Jasper - 343	313,822	35 years	(12)%	2.86%	R2	19 years, 9 months, 18 days
149	Jasper - 344	51,164	65 years	(12)%	3.19%	S1	23 years, 9 months, 18 days
150	Jasper - 345	31,271	40 years	(12)%	3.36%	S2	21 years, 4 months, 24 days
151	Jasper - 345.5	132	40 years	(12)%	4.52%	S2	24 years, 8 months, 12 days
152	Jasper - 346	1,051	42 years	(12)%	4.62%	R1	22 years, 3 months, 19 days
153	Total Jasper	425,749					
154	Urq 1 & 2 - 341	1,272	55 years	(9)%	7.37%	R2.5	10 years, 4 months, 24 days
155	Urq 1 & 2 - 342	193	55 years	(9)%	6.22%	R2	10 years, 2 months, 12 days
156	Urq 1 & 2 - 343	674	35 years	(9)%	7.37%	R2	10 years, 1 month, 6 days
157	Urq 1 & 2 - 344	4,177	65 years	(9)%	6.24%	S1	10 years
158	Urq 1 & 2 - 345	207	40 years	(9)%	8.42%	S2	10 years, 2 months, 12 days
159	Urq 1 & 2 - 346	116	42 years	(9)%	10.38%	R1	10 years
160	Total Urq 1 & 2	6,639					
161	Urq 3 - 341	354	55 years	(9)%	7.37%	R2.5	10 years, 4 months, 24 days
162	Urq 3 - 342	8	55 years	(9)%	6.22%	R2	10 years, 2 months, 12 days

163	Urq 3 - 343	369	35 years	(9)%	7.37%	R2	10 years, 1 month, 6 days
164	Urq 3 - 344	1,946	65 years	(9)%	6.24%	S1	10 years
165	Urq 3 - 345	65	40 years	(9)%	8.42%	S2	10 years, 2 months, 12 days
166	Total Urq 3	2,742					
167	Urq 4 - 341	324	55 years	(10)%	1.01%	R2.5	27 years
168	Urq 4 - 342	211	55 years	(10)%	1.73%	R2	27 years, 3 months, 19 days
169	Urq 4 - 343	4,167	35 years	(10)%	3.52%	R2	25 years, 6 months
170	Urq 4 - 344	19,272	65 years	(10)%	1.85%	S1	27 years, 1 month, 6 days
171	Urq 4 - 345	898	40 years	(10)%	3.59%	S2	27 years, 1 month, 6 days
172	Urq 4 - 346	80	42 years	(10)%	4.12%	R1	25 years, 9 months, 18 days
173	Total Urq 4	24,952					
174	Urq 5 & 6 - 341	5,195	55 years	(12)%	2.22%	R2.5	30 years
175	Urq 5 & 6 - 342	3,603	55 years	(12)%	1.67%	R2	29 years, 1 month, 6 days
176	Urq 5 & 6 - 343	226,392	35 years	(12)%	2.48%	R2	21 years, 2 months, 12 days
177	Urq 5 & 6 - 344	13,383	65 years	(12)%	2.53%	S1	29 years, 8 months, 12 days
178	Urq 5 & 6 - 345	17,240	40 years	(12)%	2.78%	S2	25 years
179	Urq 5 & 6 - 346	289	42 years	(12)%	3.57%	R1	27 years, 6 months
180	Total Urq 5 & 6	266,102					
181	Boeing Solar Project - 341	117	55 years	(10)%	5.71%	R2.5	12 years, 7 months, 6 days
182	Boeing Solar Project - 344	7,031	65 years	(10)%	5.64%	S1	12 years, 7 months, 6 days
183	Boeing Solar Project - 345	2,197	40 years	(10)%	5.68%	S2	12 years, 6 months
184	Boeing Solar Project - 346	18	42 years	(10)%	5.89%	R1	12 years
185	Total Boeing Solar	9,363					
186	Columbia Energy Center - 341 Initial Investment	[(f)]4,054					
187	Columbia Energy Center - 342 Initial Investment	[(g)]5,730					
188	Columbia Energy Center - 343 Initial Investment	[(h)]48,202					
189	Columbia Energy Center - 344 Initial Investment	[(i)]90,650					
190	Columbia Energy Center - 345 Initial Investment	[(j)]2,514					
191	Columbia Energy Center - 346 Initial Investment	[(k)]194					
192	Columbia Energy Center - 341	2,104	55 years	(11)%	0.71%	R2.5	34 years, 2 months, 12 days
193	Columbia Energy Center - 342	28	55 years	(11)%	0.56%	R2	33 years, 7 months, 6 days
194	Columbia Energy Center - 343	13,973	35 years	(11)%	0.48%	R2	30 years, 1 month, 6 days
195	Columbia Energy Center - 344		65 years	(11)%	0.33%	S1	34 years, 6 months
196	Columbia Energy Center - 345	1,239	40 years	(11)%	0.3%	S2	32 years, 6 months

197	Columbia Energy Center - 346	1,129	42 years	(11)%	1.26%	R1	30 years, 3 months, 19 days
198	Total Columbia Energy Center	169,817					
199	Hagood ICT U5 341	335	55 years	(12)%	2.61%	R2.5	36 years, 10 months, 25 days
200	Hagood ICT U5 342	337	55 years	(12)%	2.44%	R2	36 years, 1 month, 6 days
201	Hagood ICT U5 343	5,139	35 years	(12)%	1.84%	R2	27 years, 8 months, 12 days
202	Hagood ICT U5 344		0 years			0	30 years
203	Hagood ICT U5 345	2,267	40 years	(12)%	2.99%	S2	29 years, 4 months, 24 days
204	Hagood ICT U5 346		0 years			0	0 years
205	Total Hagood ICT U5	8,078					
206	Hagood ICT U6 341	668	55 years	(12)%	2.55%	R2.5	36 years, 10 months, 25 days
207	Hagood ICT U6 342	419	55 years	(12)%	2.43%	R2	36 years, 1 month, 6 days
208	Hagood ICT U6 343	5,837	35 years	(12)%	2.38%	R2	28 years, 1 month, 6 days
209	Hagood ICT U6 344	4	65 years	(12)%	1.84%	S1	38 years, 3 months, 19 days
210	Hagood ICT U6 345	3,300	40 years	(12)%	2.94%	S2	30 years, 1 month, 6 days
211	Hagood ICT U6 346	63	42 years	(12)%	3.1%	R1	32 years, 1 month, 6 days
212	Total Hagood ICT U6	10,291					
213	Transmission:						
214	Nuclear - 352	169	70 years	(10)%	2.78%	R2	37 years, 2 months, 12 days
215	Other - 352	4,043	70 years	(10)%	0.16%	R2	69 years, 7 months, 6 days
216	Parr - 352	142	70 years	(10)%	0.16%	S0.5	69 years, 7 months, 6 days
217	Saluda - 352	431	70 years	(10)%	0.16%	S0.5	69 years, 7 months, 6 days
218	Columbia Energy Ctr -352	92	70 years	(10)%	0.16%	R2	69 years, 7 months, 6 days
219	Stevens Creek - 352	38	70 years	(20)%	0.16%	S0.5	69 years, 7 months, 6 days
220	Nuclear - 352.5	407	70 years	(10)%	2.69%	R2	40 years, 7 months, 6 days
221	Industrial - 352.5	1,325	70 years	(10)%	1.47%	R2	66 years, 10 months, 25 days
222	FH Station Equip - 353	6,878	60 years	(20)%	1.95%	S0.5	48 years
223	Nuclear - 353	15,456	60 years	(20)%	2.69%	S0.5	34 years, 8 months, 12 days
224	Parr - 353	376	60 years	(20)%	1.32%	S0.5	34 years, 1 month, 6 days
225	Fairfield - 353	1,419	60 years	(20)%	1.13%	S0.5	50 years, 4 months, 24 days
226	Saluda - 353	9,764	60 years	(20)%	1.86%	S0.5	42 years, 10 months, 25 days
227	Stevens Ck - 353	4,667	60 years	(20)%	1.76%	S0.5	41 years, 6 months
228	Neal Shoals - 353	137	60 years	(20)%	2.51%	S0.5	33 years, 7 months, 6 days
229	Nuclear Step-up - 353	13,925	55 years	(20)%	2.38%	S3	37 years, 1 month, 6 days
230	Parr Step-up - 353	397	55 years	(20)%	2.27%	S3	16 years, 10 months, 25 days
231	Fairfield Step-up - 353	7,699	55 years	(20)%	1.94%	S3	42 years, 10 months, 25 days
232	Saluda Step-up - 353	3,252	55 years	(20)%	3.08%	S3	25 years, 6 months
233	Wateree Step-up - 353	5,571	55 years	(20)%	3.59%	S3	25 years, 3 months, 19 days

234	McMeekin Step-up - 353	819	55 years	(20)%	1.68%	S3	16 years, 4 months, 24 days
235	Urquhart Steam Step-up - 353	1,366	55 years	(20)%	6.56%	S3	13 years, 3 months, 19 days
236	Williams Steam Step-up - 353	1,809	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
237	Columbia Energy Ctr Int Purchase	24,173	55 years	2,000%	0.65%	n/a	35 years, 6 months
238	Cope Step-up - 353	6,020	55 years	(20)%	2.18%	S3	32 years, 3 months, 19 days
239	Williams GT - 353	5,295	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
240	Jasper Step-up - 353	19,101	55 years	(20)%	3.48%	S3	24 years, 7 months, 6 days
241	Burton Step-up - 353		0 years			0	0 years
242	Hardeeville Step-up - 353	118	55 years	(20)%	3.82%	S3	1 year
243	Coit Step-up - 353	118	55 years	(20)%	2.4%	S3	8 years, 2 months, 12 days
244	Hagood Step-up - 353	2,598	55 years	(20)%	2%	S3	32 years, 4 months, 24 days
245	Stevens Creek Step-up - 353	438	55 years	(20)%	1.81%	S3	32 years, 3 months, 19 days
246	Urquhart GT Step-up - 353	978	55 years	(20)%	2.44%	S3	13 years, 3 months, 19 days
247	Bushy Park GT 353 Step-up 353	150	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
248	Station Equip - 353	434,678	60 years	(20)%	1.95%	S0.5	48 years
249	Station Equip NND - 353.1	87,557	60 years	(20)%	3.06%	S0.5	38 years, 9 months, 18 days
250	Station Equip CIPV5 - 353.5	16,971	60 years	(20)%	2.01%	S0.5	56 years, 9 months, 18 days
251	Station Equip - Leasehold - 353.8	5,226	20 years		5.01%	SQ	6 years, 6 months
252	354	3,959	80 years	(40)%	1.34%	R3	40 years, 7 months, 6 days
253	Neal Shoals - 354	1	80 years	(40)%	1.34%	R3	40 years, 7 months, 6 days
254	355	588,965	59 years	(75)%	2.97%	L1.5	49 years, 4 months, 9 days
255	Neal Shoals - 355	21	59 years	(75)%	2.97%	L1.5	49 years, 4 months, 9 days
256	NND Trans Poles & Fixtures-355.1	163,979	59 years	(75)%	2.98%	L1.5	21 years, 8 months, 12 days
257	VC Summer Trans Poles & Fixtures-355.1	4,854	59 years	(75)%	2.97%	L1.5	57 years, 9 months, 7 days
258	355.8	2,065	20 years		5.13%	SQ	13 years, 7 months, 6 days
259	356.1	267,300	64 years	(60)%	2.59%	S0.5	51 years, 8 months, 23 days
260	356.2	3,018	64 years	(60)%	2.61%	S0.5	49 years, 2 months, 19 days
261	356.3	115,764	64 years	(60)%	2.53%	S0.5	0 years
262	356.8	2,289	20 years		9.48%	SQ	3 years, 9 months, 18 days
263	357	19,549	60 years	(5)%	1.88%	R3	48 years, 4 months, 24 days
264	358	57,700	55 years	(5)%	2.08%	R3	45 years
265	359	74	70 years		1.29%	R4	56 years, 10 months, 25 days
266	Total Transmission	1,913,141					
267	Distribution Plant:						

268	361	5,226	70 years	(10)%	1.52%	R2	54 years, 4 months, 24 days
269	361.8	38	20 years		5.7%	SQ	1 year
270	362	449,759	60 years	(10)%	1.9%	S0.5	46 years, 2 months, 12 days
271	362.5	752	60 years	(10)%	1.83%	S0.5	58 years, 1 month, 6 days
272	362.8	2,657	20 years		6.21%	SQ	10 years, 3 months, 19 days
273	364	526,712	44 years	(50)%	3.69%	R1.5	32 years, 3 months, 19 days
274	365	583,982	64 years	(10)%	1.5%	R1	52 years, 1 month, 24 days
275	URD - 366	170,665	65 years	(5)%	1.37%	R2.5	52 years, 3 months, 19 days
276	Network - 366	7,663	65 years	(5)%	1.37%	R2.5	52 years, 3 months, 19 days
277	URD - 367	523,804	50 years	(5)%	1.91%	S0.5	39 years, 6 months
278	Network - 367	10,202	50 years	(5)%	1.91%	S0.5	39 years, 6 months
279	368	551,283	46 years	(5)%	2.1%	R2	32 years, 11 days
280	O/H - 369	117,582	75 years	(80)%	2.22%	R3	53 years, 6 months, 3 days
281	U/G - 369.1	208,973	80 years	(25)%	1.44%	S3	63 years, 2 months, 23 days
282	370	26,046	22 years		2.64%	L1.5	16 years, 2 months, 12 days
283	370.3	53,575	15 years		8.39%	S1	7 years
284	370.4	13,948	12 years		11.47%	R0.5	7 years, 3 months, 19 days
285	3705	7,919	12 years		11%	R0.5	8 years
286	3706	75,055	12 years		11.47%	R0.5	7 years
287	373	407,625	42 years	(20)%	2.63%	L1	32 years, 11 months, 15 days
288	373.1		30 years	(20)%	3.94%	S1	26 years, 4 months, 24 days
289	Total Distribution	3,743,466					
290	General Plant:						
291	3901	102,273	50 years	(20)%	2.16%	S0	41 years, 7 months, 6 days
292	3902	10,223	50 years	(20)%	2.35%	R2.5	40 years, 3 months, 19 days
293	3908	145	50 years	(20)%	1.79%	S0	29 years, 2 months, 12 days
294	3909	111	50 years	(20)%	3.68%	R2.5	24 years, 7 months, 6 days
295	3911	8,033	20 years		4.33%	SQ	10 years, 8 months, 12 days
296	3912	1,253	5 years		15.37%	SQ	2 years
297	3913	115	10 years		21.4%	SQ	2 years
298	3915	1,788	5 years		15.37%	SQ	2 years
299	3919		0 years			0	0 years
300	393	80	25 years		3.69%	SQ	9 years, 3 months, 19 days
301	3941	523	20 years		4.76%	SQ	11 years, 8 months, 12 days
302	3942	3,495	20 years		3.99%	SQ	12 years, 7 months, 6 days
303	3943	201	20 years		4.39%	SQ	7 years, 2 months, 12 days
304	3944	242	20 years		6.04%	SQ	9 years, 1 month, 6 days

305	3951	1,892	20 years		3.19%	SQ	11 years, 2 months, 12 days
306	3952	723	20 years		4.52%	SQ	11 years, 7 months, 6 days
307	3953	3,978	20 years		3.62%	SQ	11 years, 8 months, 12 days
308	397	6,031	10 years		7.45%	SQ	8 years, 3 months, 19 days
309	397.5	248	10 years		11.93%	SQ	7 years, 6 months
310	398	6,797	20 years		3.23%	SQ	12 years, 8 months, 12 days
311	Total General Plant	148,151					
312	Solar Farm						
313	341	30	55 years	(6)%	5.84%	R2.5	12 years, 7 months, 6 days
314	346	2	42 years	(6)%	6.06%	R1	12 years
315	Total Solar Farm	32					

FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Method of Determination of Depreciation Charges:

The annual Provision for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, are computed based on the number of days that the plant was in service.

In addition to Depreciation Provisions provided by the application of the reported rates herein, the Company also recognized $6,796,540 of electric and $530,319 of common depreciation related to vehicles, as well as, $3,937,867 of electric and $5,494,928 of common amortization related to software over their expected useful lives using the straight line method. See allocation of Common Plant on pages 356.1 and 356.2.

The information shown here reflects the 2020 study and plant information filed in the 2021 DESC FERC Form No. 1 filing. We added the solar farm data that was previously omitted in the 2021 DESC FERC Form No. 1 filing'

As indicated in this schedule in the Company's 2020 FERC Form No.1, the Company presented an electric and common plant depreciation study based on plant balances as of December 31, 2018 to the Public Service Commission of South Carolina (SCPSC) for approval in its retail electric base rate proceeding before the SCPSC in Docket No. 2020-125-E. In the comprehensive settlement agreement approved by the SCPSC in Docket No. 2020-125-E, the SCPSC incorporated certain adjustments proposed by a witness for the South Carolina Office of Regulatory Staff (ORS) to the depreciation study rates presented by the Company. Accordingly, pursuant to the order issued by the SCPSC in Docket No. 2020-125-E, in September 2021 the Company implemented the results of the depreciation study as modified by the witness for the ORS. On March 15, 2022, in Docket No. ER22-1344-000, the Company submitted to the FERC a limited-scope, single issue filing pursuant to Section 205 of the Federal Power Act and Part 35 of the Regulations of the FERC to implement the new depreciation rates in its open access transmission tariff formula rate template. See Docket No. ER22-1344-000 for additional details.

(b) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(c) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(d) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(e) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(f) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(g) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(h) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(i) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(j) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(k) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	State assessment for the support of the Public Service Commission of South Carolina (SCPSC)	4,554,984		4,554,984		Electric	928	4,554,984				
2	Annual charges assessed by the Federal Energy Regulatory Commission (FERC)	2,286,285		2,286,285		Electric	928	2,286,285				
3	Company labor, legal, consulting and miscellaneous expenses related to the Company's retail electric base rate case before the SCPSC. Amortization period September 2021 - July 2037. SCPSC Docket No. 2020-125-E				2,618,799	Electric	928			928	180,048	2,438,751
4	Company labor, legal, consulting and miscellaneous expenses related to the Company's retail electric base rate case before the SCPSC. SCPSC Docket No. 2024-34-E		58,813	58,813		Electric	928	58,813	311,422	928		311,422
5	Company labor, legal, consulting and miscellaneous expenses related to the Company's annual review of base fuel rates before the SCPSC. SCPSC Docket Nos. 2022-259-E, 2023-2-E, and 2024-2-E		378,592	378,592		Electric	928	378,592				
6	Company labor, legal, consulting and miscellaneous expenses related to the Company's Integrated Resource Plan before the SCPSC. SCPSC Docket No. 2023-9-E		102,478	102,478		Electric	928	102,478				
7	Company legal expenses related to the South Carolina Office of Regulatory Staff's petition for a declaratory order before the SCPSC. SCPSC Docket No. 2023-38-E		173,465	173,465		Electric	928	173,465				
8	Company labor related to the Company's transmission filings before the FERC. FERC Docket Nos. ER10-516, ER10-855, and ER10-1268		21,491	21,491		Electric	928	21,491				
9	Company labor and legal expenses related to the FERC Audit of Dominion Energy Services, Inc. and Dominion Energy Southeast Services, Inc. FERC Docket No. FA22-4-000		74,312	74,312		Electric	928	74,312				
10	Company labor, legal, consulting and miscellaneous expenses related to proceedings. Various Dockets		375,405	375,405		Electric	928	375,405				
46	TOTAL	6,841,269	1,184,556	8,025,825	2,618,799			8,025,825	311,422		180,048	2,750,173

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:
   - A. Electric R, D and D Performed Internally:
     1. Generation
        - a. hydroelectric
          - i. Recreation fish and wildlife
          - ii. Other hydroelectric
        - b. Fossil-fuel steam
        - c. Internal combustion or gas turbine
        - d. Nuclear
        - e. Unconventional generation
        - f. Siting and heat rejection
     2. Transmission
        - a. Overhead
        - b. Underground
     3. Distribution
     4. Regional Transmission and Market Operation
     5. Environment (other than equipment)
     6. Other (Classify and include items in excess of $50,000.)
     7. Total Cost Incurred
   - B. Electric, R, D and D Performed Externally:
     1. Research Support to the electrical Research Council or the Electric Power Research Institute
     2. Research Support to Edison Electric Institute
     3. Research Support to Nuclear Power Groups
     4. Research Support to Others (Classify)
     5. Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A. Electric R, D, & D Performed Internally:						
2	(1) Generation	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
3	(2) Transmission	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
4	(3) Distribution	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
5	B. Electric R, D, & D Performed Externally:						
6	(1) Research Support to EPRI						
7	Fossil Steam Plants and Combustion						
8	Turbine Programs	Heat Recovery Steam Generators		44,370	930.2	44,370	
9		Hydropower Generation		44,370	930.2	44,370	
10		Power Plant Piping		44,370	930.2	44,370	
11		Gas Turbine Life Cycle Management		44,370	930.2	44,370	
12		Integrated Asset Management		44,370	930.2	44,370	
13		Plant Management Essentials		44,370	930.2	44,370	
14		Boiler and Turbine Steam and Cycle Chemistry		44,370	930.2	44,370	
15		Water Treatment Technologies		44,370	930.2	44,370	
16		Steam Turbines and Auxiliary Systems		44,370	930.2	44,370	

17		Generators and Auxiliary Systems		44,370	930.2	44,370	
18	Transmission and Substation - Programs	Transmission Asset Management Analytics: Principles and Practices		1,991	930.2	1,991	
19		Substations Asset Data Analytics		16,684	930.2	16,684	
20		Overhead Transmission Asset Data Analytics		9,875	930.2	9,875	
21		Inspection and Assessment		10,837	930.2	10,837	
22		Structure and Sub-Grade Corrosion Management		11,998	930.2	11,998	
23		Lightning Performance and Grounding of Transmission Lines		20,318	930.2	20,318	
24		Line Design Tools and Practices for Construction and Management		16,255	930.2	16,255	
25		Modeling and Analytics for Emerging Technologies		33,365	930.2	33,365	
26		Operator Support Tools and Methods for Emerging Technologies		33,365	930.2	33,365	
27		Emerging Technologies and Technology Transfer		23,973	930.2	23,973	
28		Polymer and Composite Overhead Transmission Line Insulators		18,383	930.2	18,383	
29		Overhead Line Ratings and Increased Power Flow		12,772	930.2	12,772	
30		High Temperature Operation of Overhead Lines		14,900	930.2	14,900	
31		Line Switch Mangement		9,869	930.2	9,869	
32		Principles and Practices of Underground Transmission		10,077	930.2	10,077	
33		Transformer Life Management		37,409	930.2	37,409	
34		Balance of Substations: Batteries, CCVT's, Arresters, & Ratings		11,379	930.2	11,379	
35		Advanced Metering Systems		41,953	930.2	41,953	
36	Power Quality and Renewables Programs	Bulk Energy Storage		44,370	930.2	44,370	
37		Cyber Security for Generation Assets		44,370	930.2	44,370	
38		Achieving Cost-Effective Edge-of-Grid PQ Compatibility		40,030	930.2	40,030	
39	Nuclear Power Programs	Nuclear Power		600,885	524.0	600,885	
40	Nuclear Supplemental Projects	SGMP - Steam Generator Management Program		68,837	524.0	68,837	
41		MRP - Materials Reliability Program		159,008	524.0	159,008	
42		STE - Standardized Task Evaluations for Portable Qualifications		18,290	524.0	18,290	
43		External Hazards Data Collection		8,000	524.0	8,000.0	
44		Pressurized Water Reactor Technical Strategy Group		7,334	524.0	7,334	
45		FTREX		3,200	524.0	3,200	
46		Risk-Informed Classification & Treatment		6,667	524.0	6,667	
47		Digital Systems Engineering Users Group		6,667	524.0	6,667	
48		Fuel Reliability Program		77,471	524.0	77,471	
49		Extreme Cold Weather Preparedness & Operation		6,667	524.0	6,667	
50	(4) Research Support to Others						
51	Clemson University Electric Power Research Alliance	CUEPRA		30,000	588.0	30,000	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	54,694,931		
4	Transmission	6,688,322		
5	Regional Market			
6	Distribution	13,002,247		
7	Customer Accounts	12,188,394		
8	Customer Service and Informational	2,184,596		
9	Sales	1,163,433		
10	Administrative and General	58,868,521		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	148,790,444		
12	Maintenance			
13	Production	23,994,562		
14	Transmission	2,489,577		
15	Regional Market			
16	Distribution	11,247,333		
17	Administrative and General	648,271		
18	TOTAL Maintenance (Total of lines 13 thru 17)	38,379,743		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	78,689,493		
21	Transmission (Enter Total of lines 4 and 14)	9,177,899		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	24,249,580		
24	Customer Accounts (Transcribe from line 7)	12,188,394		
25	Customer Service and Informational (Transcribe from line 8)	2,184,596		
26	Sales (Transcribe from line 9)	1,163,433		
27	Administrative and General (Enter Total of lines 10 and 17)	59,516,792		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	187,170,187		187,170,187

29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission	10,780		
36	Distribution	16,626,207		
37	Customer Accounts	6,000,326		
38	Customer Service and Informational	338,324		
39	Sales	1,434,079		
40	Administrative and General	10,445,985		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	34,855,701		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution	3,622,247		
49	Administrative and General	10,372		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,632,619		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)	10,780		
57	Distribution (Lines 36 and 48)	20,248,454		
58	Customer Accounts (Line 37)	6,000,326		
59	Customer Service and Informational (Line 38)	338,324		
60	Sales (Line 39)	1,434,079		
61	Administrative and General (Lines 40 and 49)	10,456,357		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	38,488,320		38,488,320
63	Other Utility Departments			
64	Operation and Maintenance			

65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	225,658,507		225,658,507
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant		56,954,950	56,954,950
69	Gas Plant		11,521,892	11,521,892
70	Other (provide details in footnote):		1,157,486	[a]1,157,486
71	TOTAL Construction (Total of lines 68 thru 70)		69,634,328	69,634,328
72	Plant Removal (By Utility Departments)			
73	Electric Plant		9,560,979	9,560,979
74	Gas Plant		170,958	170,958
75	Other (provide details in footnote):		3,017	[b]3,017
76	TOTAL Plant Removal (Total of lines 73 thru 75)		9,734,954	9,734,954
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Non Utility Property	1,703		1,703
80	Non Operating Expenses	1,296,414		[c]1,296,414
81	Other Work in Progress	1,299,087		1,299,087
82	Other Balance Sheet Payroll (provide details in footnote)	2,723,498		[d]2,723,498
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	5,320,702		5,320,702
96	TOTAL SALARIES AND WAGES	230,979,209	79,369,282	[e]310,348,491

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: SalariesAndWagesUtilityPlantConstructionOther

Common Plant

(b) Concept: SalariesAndWagesPlantRemovalOther

Common Plant

(c) Concept: SalariesAndWagesOtherAccounts

Other Deductions

(d) Concept: SalariesAndWagesOtherAccounts

Demand Side Management Deferrals, Regulatory Assets, Preliminary Survey and Investigation, Accounts Receivable for insurance claims.

(e) Concept: SalariesAndWagesGeneralExpense

Amounts reported on pages 354 and 355 exclude incentive compensation.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Common Utility Plant In Service		Balance End of Year
118-603 Misc Intangible Plant	$	152,139,705
118-689 Land and Land Rights		12,536,480
118-690 Structures and Improvements		189,150,056
118-691 Office Furniture and Equipment		11,560,279
118-692 Transportation Equipment		1,971,591
118-694 Tools, Shop and Garage Equipment		2,293,894
118-695 Laboratory Equipment		119,518
118-696 Power-Operated Equipment		26,203,710
118-697 Communication Equipment		13,612,965
118-698 Miscellaneous Equipment		9,124,778
118-699 ARC Common Gen Plant		3,749
	$	418,716,725

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classified.

As a result of the adoption of new accounting guidance for leases in 2019, Common Utility Plant includes the following balances for operating leases as of December 31, 2023:

Plant Account		Balance End of Year
689 - Land and Land Rights	$	8,851,846
690 - Structures and Improvements		—
691 - Office Furniture and Equipment		271,244
697 - Communication Equipment		1,599,245
Total	$	10,722,335

For the formula rate approved in the FERC proceeding listed on page 106, Common Utility Plant will exclude the operating lease balances identified above.

Construction Work in Progress - Common Utility Plant

Description of Project		Balance End of Year
DESC Facilities Renovation	$	6,602,174
DESC JIC Network Upgrade		1,402,574
CIS Service Order Architecture		793,113
Other Projects < $700,000		5,638,646
Total	$	14,436,507

Common Plant in Service and Depreciation Reserve

Allocable to Utility Departments

Common Utility		Total (a)		Electric (b)		Gas (c)
Plant Allocable to Utility department (1)	$	418,716,725	$	374,918,956	$	43,797,769
Less:						
Common Depreciable Reserve Allocable to Utility Department (2)		202,698,776		181,496,484		21,202,292
Net Common Plant Allocable to Utility Departments	$	216,017,949	$	193,422,472	$	22,595,477

(1) This allocation is based on functional use by Departments.
Allocation: Electric 89.54% and Gas 10.46%
(2) This allocation is based on functional use by Departments of common depreciable property.
Allocation is the same as in note (1)

Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis.

Common Utility Plant Classification July 24, 1948.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights	804	804	804	804
5	Ancillary Services	8,101	10,397	10,135	7,590
6	Other Items (list separately)				
7	Black Start Service	54	54	54	54
8	Day-Ahead Load Response Charge Allocation	32	32	32	32
9	Market Monitoring Unit (MMU) Funding	3	3	3	3
10	PJM Settlement, Inc.	317	500	609	778
11	Real-Time Load Response Charge Allocation	7	7	7	7
12	FERC Annual Recovery	34	34	34	34
13	Emergency Energy	(8,760)	(8,727)	(8,727)	(8,727)
14	Balancing Transmission Congestion	2,763	2,763	2,763	2,763
15	Transmission Losses	(113)	(113)	(113)	(113)
16	Reversal of Estimated Transmission for December 2022	(1,340)	(1,340)	(1,340)	(1,340)
17	Pre-Emergency and Emergency Load Response		63,283	63,283	68,507
46	TOTAL	1,902	67,697	67,544	70,392

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0	[b]0	[c]6,782	37,090	MW	170,874
2	Reactive Supply and Voltage	[d]0	[e]0	[f]9,685	37,090	MW	323,815
3	Regulation and Frequency Response	[g]0	[h]0	[i]456	1,588	MW	74,668
4	Energy Imbalance	[j](63)	[k]MWH	[l]10,891	[m]2,972	MWH	[n]145,250
5	Operating Reserve - Spinning	[o]0	[p]0	[q]8,109	1,828	MW	122,571
6	Operating Reserve - Supplement	[r]0	[s]0	[t]978	1,828	MW	178,185
7	Other	[u]0	[v]0	[w]75,046	0		
8	Total (Lines 1 thru 7)	(63)		111,947	[x]82,396		[y]1,015,363

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(c) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 1	0.067168	% Load Ratio Share	$	592
PJM Settlement, Inc.	400 MW/ 400 MWH	MW, MWH		150
Santee Cooper OATT Rate Schedule 1	25,726 MW/ 25,009 MWH	MW,MWH		6,040
		Total	$	6,782

(d) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(e) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(f) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 2	0.067168	% Load Ratio Share	$	2,402
PJM Settlement, Inc.	400 MW/ 400 MWH	MW,MWH		309
Santee Cooper OATT Rate Schedule 2	25,726 MW/ 25,009 MWH	MW,MWH		6,974
		Total	$	9,685

(g) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(h) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(i) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 3	0.067168	% Load Ratio Share	$ 456

(j) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.4, Column D for detail on number of units.

(k) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.4, Column D for detail on units of measure.

(l) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 4	-63	MWH	$ 10,891
		Total	$ 10,891

(m) Concept: AncillaryServicesSoldNumberOfUnits

Energy Imbalance breakdown by MWH:

Gross Band 1	Over Supplied	Under Supplied*
1,592	745	635

(n) Concept: AncillaryServicesSoldAmount

Energy Imbalance breakdown by dollar amount:

Net Band 1	Over Supplied	Under Supplied*
$50,256	$(33,607)	$128,601

* Reported value for Under Supplied is net of Energy Imbalance Penalties credited to users of the transmission system.

(o) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.5, Column D for detail on number of units.

(p) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.5, Column D for detail on units of measure.

(q) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 5	0.067168	% Load Ratio Share	$ 978
PJM Settlement, Inc.	400 MW/ 400 MWH		7,131
		Total	$ 8,109

(r) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.6, Column D for detail on number of units.

(s) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.6, Column D for detail on units of measure.

(t) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure	Amount
Duke Energy Carolinas, LLC			
OATT Rate Schedule 6	0.067168	% Load Ratio Share	$ 978

(u) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.7, Column D for detail on number of units.

(v) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.7, Column D for detail on units of measure.

(w) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC				
OATT Direct Assignment Charges and Other Miscellaneous Adjustments.			$	13,048
Black Start Service			$	54
Day-Ahead Load Response Charge Allocation				32
Market Monitoring Unit (MMU) Funding				3
PJM Settlement, Inc.				778
Real-Time Load Response Charge Allocation				7
FERC Annual Recovery				34
Emergency Energy				(8,727)
Balancing Transmission Congestion				2,763
Transmission Losses				(113)
Pre-Emergency and Emergency Load Response				68,507
Reversal of Estimated Transmission for December 2022				(1,340)
Total		Total	$	75,046

(x) Concept: AncillaryServicesSoldNumberOfUnits

Total is not meaningful due to the summation of dissimilar units of measure.

(y) Concept: AncillaryServicesSoldAmount

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	3,754	24	[a]8	[a]3,510	244				
2	February	3,484	4	9	3,274	210				
3	March	3,485	15	8	3,261	224				
4	Total for Quarter 1				10,045	678				
5	April	3,182	20	18	3,008	174				
6	May	3,520	16	17	3,317	203				
7	June	4,358	29	17	4,122	236				
8	Total for Quarter 2				10,447	613				
9	July	4,623	20	17	4,359	264				
10	August	4,761	14	17	4,487	274				
11	September	4,562	6	17	4,204	256			102	
12	Total for Quarter 3				13,050	794			102	
13	October	3,474	3	18	3,142	179			153	
14	November	3,617	30	8	3,384	233				
15	December	4,012	21	8	3,767	245				
16	Total for Quarter 4				10,293	657			153	
17	Total				43,835	2,742			255	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: HourOfMonthlyPeakExcludingIsoAndRto

All times shown in Hour Ending (HE) format.

(b) Concept: FirmNetworkServiceForSelf

For all values shown in column (e):

The Company utilizes grandfathered service for its retail customers and has not executed a network integration transmission service agreement under the OATT.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-03-22	Year/Period of Report End of: 2023/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	[a][b]21,026,077
3	Steam	3,892,870	23	Requirements Sales for Resale (See instruction 4, page 311.)	[c]787,633
4	Nuclear	5,010,406	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	133,358
5	Hydro-Conventional	244,199	25	Energy Furnished Without Charge	[d]0
6	Hydro-Pumped Storage	396,796	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	69,290
7	Other	9,725,982	27	Total Energy Losses	1,029,391
8	Less Energy for Pumping	543,880	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	18,726,373	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	23,045,749
10	Purchases (other than for Energy Storage)	4,307,010			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	[e][f]459,442			
17	Delivered	[g][h]447,076			
18	Net Transmission for Other (Line 16 minus line 17)	12,366			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	23,045,749			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2024-03-22	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSalesToUltimateConsumers

Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure the total here agrees with page 300-301, Line 10 Column D.

(b) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	72,770
Commercial/Industrial	138,201
Street Lighting	53,248
Other Public Authorities	702
	264,921

(c) Concept: MegawattHoursSoldRequirementsSales

Includes Unmetered MWH Sales as follows:

Residential	72,770
Commercial/Industrial	138,201
Street Lighting	53,248
Other Public Authorities	702
	264,921

(d) Concept: NonChargedEnergy

Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure that Line 22 above agrees with page 300-301, Line 10 Column D.

(e) Concept: ElectricPowerWheelingEnergyReceived

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from DESC's system. The MWH supporting these transactions are included in DESC's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j).

The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,270,143	1,234,709
Page 401a	459,442	447,076
Difference	810,701	787,633

DESC Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 21	753,497	731,550
Page 329 line 22	57,204	56,083
Total	810,701	787,633

(f) Concept: ElectricPowerWheelingEnergyReceived

This revenue is reflective of 763 MWH from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023.

(g) Concept: ElectricPowerWheelingEnergyDelivered

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from DESC's system. The MWH supporting these transactions are included in DESC's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j).

The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,270,143	1,234,709
Page 401a	459,442	447,076
Difference	810,701	787,633

DESC Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 21	753,497	731,550
Page 329 line 22	57,204	56,083
Total	810,701	787,633

(h) Concept: ElectricPowerWheelingEnergyDelivered

This revenue is reflective of 763 MWH from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	[a]1,867,622	8,892	3,880	24	[b]8
30	February	1,627,191	12,692	3,529	4	9
31	March	1,715,643	26,985	3,536	15	8
32	April	1,688,532	3,521	3,331	5	18
33	May	1,804,243	3,234	3,799	9	17
34	June	2,033,525	20,940	4,155	29	17
35	July	2,475,664	11,586	4,626	20	17
36	August	2,488,821	16,594	4,785	14	17
37	September	1,985,341	9,761	4,486	6	17
38	October	1,735,528	21,221	3,307	4	17
39	November	1,709,548	3,550	3,725	29	8
40	December	1,902,779	579	4,125	20	8
41	Total	23,034,437	139,555			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: EnergyActivity
Certain amounts have been updated from amounts originally reported in quarterly filings.
(b) Concept: HourOfMonthlyPeak
All Times are in Hour Ending (HE) format.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0	Plant Name: Canadys	Plant Name: Coit #1 Peaking Unit	Plant Name: Coit #2 Peaking Unit	Plant Name: Coit Combined	Plant Name: Columbia Energy Center	Plant Name: Cope	Plant Name: Hagood #4	Plant Name: Hagood #5	Plant Name: Hagood #6	Plant Name: Hagood Combined	Plant Name: Hardeeville Peaking	Plant Name: Jasper	Plant Name: Major Maintenance Accrual	Plant Name: McMeekin	Plant Name: Parr #1 & #2	Plant Name: Parr #3 & #4	Plant Name: Parr Combined	Plant Name: Urquhart	Plant Name: Urquhart #1 Peaking	Plant Name: Urquhart #2 Peaking	Plant Name: Urquhart #3 Peaking	Pla Nam Urqu #4 Peak
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)		Steam[a]	Gas Turbine	Gas Turbine		Combined Cycle	Steam	Gas Turbine	Gas Turbine	Gas Turbine		Gas Turbine	Combined Cycle	footnote[b]	Steam	Gas Turbine	Gas Turbine		Steam	Gas Turbine	Gas Turbine	Gas Turbine	Tu
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		Outdoor-Boiler	Package	Package		Package	Conventional	Package	Package	Package		Package	Package		Semi-Outdoor	Package	Package	See footnote[d]	Conventional	Package	Package	Package	Pac
3	Year Originally Constructed		1962	1969	1969		2004	1996	1991	2000	1981		1968	2004		1958	1970	1971		1953	1969	1969	1969	
4	Year Last Unit was Installed		1967	1969	1969		2004	1996	1991	2000	1981		1968	2004		1958	1970	1971		1955	1969	1969	1969	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			19.64	19.64	39.27	658.70	417.36	121.89	27.40	27.94	177.23		1,081.97		293.76				100.00	19.64	16.32	16.32	[illegible]
6	Net Peak Demand on Plant - MW (60 minutes)			14	13	27	595	425	87	21	23	131		972		513	13	36	49	96	11	12	12	
7	Plant Hours Connected to Load			38	31	69	6,787	6,330	272	192	193	657		23,571		5,503	5	6	11	1,737	37	20	25	
8	Net Continuous Plant Capability (Megawatts)																							
9	When Not Limited by Condenser Water			18	18		592	415	95	21	21			1,000		250				96	16	17	15	

10	When Limited by Condenser Water			14	12		520	415	88	18	20			902		250				95	13	14	12	
11	Average Number of Employees						26	62	0					33		40			2	48				
12	Net Generation, Exclusive of Plant Use - kWh			275,000	125,000	400,000	2,465,905,000	1,375,971,000	17,414,000	2,655,000	3,255,000	23,324,000		5,323,095,000		729,071,000	52,000	147,000	199,000	94,760,000	227,000	118,000	207,000	1,30
13	Cost of Plant: Land and Land Rights		5,530,554	36,023	27,736	63,759		3,214,010	96,047			96,047		2,736,178		15,668	10,899	4,951	15,850	2,616,353				
14	Structures and Improvements			78,164	69,100	147,264	9,648,702	82,859,197	3,910,599	335,181	672,533	4,918,313		28,212,926		23,747,625	126,336	8,364	134,700	32,835,984	516,413	404,411	388,648	63
15	Equipment Costs			3,546,828	2,721,909	6,268,737	322,606,260	540,970,453	35,146,874	7,786,246	9,573,406	52,506,526		511,335,855		183,785,791	1,271,129	626,481	1,897,610	117,369,921	2,089,389	860,757	2,648,454	26,87
16	Asset Retirement Costs							1,612,437	(17,960,494)			(17,960,494)				(3,402,691)				64,263,498				
17	Total cost (total 13 thru 20)		5,530,554	3,661,015	2,818,745	6,479,760	332,254,962	628,656,097	21,193,026	8,121,427	10,245,939	39,560,392		542,284,959		204,146,393	1,408,364	639,796	2,048,160	217,085,756	2,605,802	1,265,168	3,037,102	27,51
18	Cost per KW of Installed Capacity (line 17/5) Including			186.4061	143.5206	165.0053	504.4101	1,506.2682	173.8701	296.4024	366.7122	223.2150		501.2015		694.9428				2,170.8576	132.6783	77.5225	186.0969	467.
19	Production Expenses: Oper, Supv, & Engr					2,254	810,048	2,039,858				1,816		846,860	0	832,047			21,342	52,806				
20	Fuel					52,707	66,172,565	50,213,828				1,592,754		148,316,524	0	31,794,329			781,183	2,812,879				
21	Coolants and Water (Nuclear Plants Only)														0									
22	Steam Expenses							3,393,413							0	1,474,719				274				
23	Steam From Other Sources														0									
24	Steam Transferred (Cr)														0									
25	Electric Expenses					13,690	2,633,047	5,798,502				25,983		(2,851,108)	(5,392,732)	1,320,107			49,452	191,487				
26	Misc Steam (or Nuclear) Power Expenses							1,440,798							0	703,522				48,817				
27	Rents													13,549	0									
28	Allowances						6							17	0	3								

29	Maintenance Supervision and Engineering					23	1,817,838	222,895				75,173		276,335	0	231,034				19,217				
30	Maintenance of Structures						5,115	225,043				15,542		301,265		143,067				14,585				
31	Maintenance of Boiler (or reactor) Plant						312,731	2,204,791							11,205	676,508				11,679				
32	Maintenance of Electric Plant					63,575	7,131,512	408,554				100,155		10,955,807	8,828,547	177,682			22,775	171,831				
33	Maintenance of Misc Steam (or Nuclear) Plant					11,094	959,543	710,991				247,403		313,503	50,357	437,156			26	16,295				
34	Total Production Expenses		0			143,343	79,842,405	66,658,673	0			2,058,826		158,172,752	3,497,377	37,790,174			874,778	3,339,870	0			
35	Expenses per Net kWh					0.3584	0.0324	0.0484				0.0883	0	0.0297		0.0518			4.3959	0.0352	0			

35	**Plant Name**	Coit Combined	Coit Combined	Columbia Energy Center	Columbia Energy Center	Cope	Cope	Cope	Hagood Combined	Hagood Combined	Jasper	Jasper	McMeekin	McMeekin	Parr Combined	Parr Combined	Urquhart	Urquhart	Urquhart Combined 1-4	Urquhart Combined 1-4	Urquhart Combined Cycle	Urquhart Combined Cycle	V.C. Summer (2/3rds)	Wateree	Wateree
36	Fuel Kind	Gas	Oil	Gas	Oil	Coal	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Nuclear	Coal	Oil
37	Fuel Unit	Mcf	bbl	Mcf	bbl	T	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	g	T	bbl
38	Quantity (Units) of Fuel Burned	7,963	188	17,119,004	8,669	139,794	10,707,684	1,611	295,380	4,095	37,567,414	1,471	7,332,881		64	555	1,045,379		27,219	230	15,004,570	1,085	792,645	748,662	27,213
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,030	142,000	1,037	142,000	12,485	1,030	142,000	1,029	142,000	1,028	142,000	1,034		1,032	142,000	1,032		1,033	142,000	1,032	142,000	65	12,482	142,000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.777	151.743	3.256	113.079	129.502	2.799	127.575	3.256	167.669	3.937	184.983	4.335		(11.816)	150.215	2.725	152.621	11.6900		3.5780			94.333	121.195
41	Average Cost of Fuel per Unit Burned	3.777	120.550	3.256	116.931	127.139	2.799	124.856	3.256	152.502	3.937	153.796	4.335		(11.816)	1,436.185	2.725		11.6900	1,228.1210	3.5780	2,382.9690	41.74	99.821	136.148
42	Average Cost of Fuel Burned per Million BTU	3.667	20.213	3.165	19.606	5.092	2.717	20.935	3.165	25.570	3.830	25.787	4.192		(11.450)	240.809	2.641		11.3160	205.9220	3.4670	399.5590	0.643	3.999	22.828
43	Average Cost of Fuel Burned per kWh Net Gen	0.086	0.045	0.027		[f]0.035			0.043	0.642	[g]0.028		0.044		(0.378)	4.046	[h]0.030		0.1740	12.8630	[i]0.0290		[j]0.007	[k]0.045	
44	Average BTU per kWh Net Generation					10,103.000[l]							10,410.000				11,362.000[m]						10,262,730.000[n]	10,865.000[o]	

FOOTNOTE DATA

(a) Concept: PlantKind

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

(b) Concept: PlantKind

The major maintenance accrual represents an SCPSC approved (SCPSC Docket Nos. 2009-489-E, 2012-218-E, 2017-210-E and 2020-125-E) annual turbine-generator maintenance expense accrual. Prior to September 2021, the annual accrual was $18.4 million. Effective September 2021, the SCPSC approved an annual accrual of $24.8 million. Under this mechanism, the Company records an annual expense accrual of $24.8 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate. For the year ended December 31, 2023 the Company incurred actual expenses of $20.0 million for major maintenance that is subject to the accrual. Cumulative costs for turbine- generator maintenance in excess of cumulative collections (accruals) are classified as a regulatory asset on the balance sheet.

(c) Concept: PlantKind

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the Public Service Commission of South Carolina (SCPSC), estimated refueling outage operation and maintenance costs for the five outages from Spring 2014 through Spring 2020 were being accrued over the 90 month period (January 2013 through June 2020) covered by these outages. By Order dated November 24, 2020, issued in Docket No. 2020-172-E, the SCPSC authorized the Company to continue to recognize a levelized nuclear outage accrual and explained that the Company will address the accrual in its then upcoming electric base rate filing. By Order No. 2021-570 issued in Docket No. 2020-125-E, the SCPSC approved the Company's request to extend the outage accrual mechanism for another five outages covering the period July 2020 through December 2027.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

(d) Concept: PlantConstructionType

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

(e) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(f) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(g) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(h) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(i) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(j) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(k) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration

All fuels.

(l) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

All fuels.

(m) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

All fuels.

(n) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

All fuels.

(o) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration

All fuels.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 1894 Plant Name: Parr	FERC Licensed Project No. 2535 Plant Name: Stevens Creek	FERC Licensed Project No. 516 Plant Name: Saluda
1	Kind of Plant (Run-of-River or Storage)		[(a)] Run-of-River	[(b)] Run-of-River	[(c)] Storage
2	Plant Construction type (Conventional or Outdoor)		Conventional	Conventional	Conventional
3	Year Originally Constructed		1914	1914	1930
4	Year Last Unit was Installed		1921	1926	1971
5	Total installed cap (Gen name plate Rating in MW)		14.88	17.28	219.35
6	Net Peak Demand on Plant-Megawatts (60 minutes)		13	25	184
7	Plant Hours Connect to Load		8,726	8,683	6,531
8	**Net Plant Capability (in megawatts)**				
9	(a) Under Most Favorable Oper Conditions		7	17	198
10	(b) Under the Most Adverse Oper Conditions		4	12	198
11	Average Number of Employees		5	3	6
12	Net Generation, Exclusive of Plant Use - kWh		47,346,000	80,923,000	109,483,000
13	**Cost of Plant**				
14	Land and Land Rights		643,326	406,315	6,177,894
15	Structures and Improvements		2,088,964	3,354,527	8,269,478
16	Reservoirs, Dams, and Waterways		6,017,395	15,311,320	354,579,754
17	Equipment Costs		9,050,879	7,229,639	30,989,307
18	Roads, Railroads, and Bridges		124,198	128,812	233,527
19	Asset Retirement Costs				
20	Total cost (total 13 thru 20)		17,924,762	26,430,613	400,249,960
21	Cost per KW of Installed Capacity (line 20 / 5)		1,204.6211	1,529.5494	1,824.7092
22	**Production Expenses**				
23	Operation Supervision and Engineering		646,354	128,235	132,773
24	Water for Power				
25	Hydraulic Expenses		184,819	84,171	287,608

26	Electric Expenses			418,969		361,833
27	Misc Hydraulic Power Generation Expenses			85,804	89,021	69,879
28	Rents					1,694
29	Maintenance Supervision and Engineering			7,138	1,229	67,264
30	Maintenance of Structures			200,919	29,190	131,943
31	Maintenance of Reservoirs, Dams, and Waterways			862,085	113,243	33,112
32	Maintenance of Electric Plant			72,042	443,884	101,807
33	Maintenance of Misc Hydraulic Plant			213,674	114,141	216,951
34	Total Production Expenses (total 23 thru 33)			2,691,804	1,003,114	1,404,864
35	Expenses per net kWh			0.0569	0.0124	0.0128

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.
(b) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.
(c) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 1984 Plant Name: Fairfield
1	Type of Plant Construction (Conventional or Outdoor)		Outdoor
2	Year Originally Constructed		1978
3	Year Last Unit was Installed		1978
4	Total installed cap (Gen name plate Rating in MW)		586.8
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0	495
6	Plant Hours Connect to Load While Generating	0	3,099
7	Net Plant Capability (in megawatts)	0	576
8	Average Number of Employees		22
9	Generation, Exclusive of Plant Use - kWh	0	396,796,000
10	Energy Used for Pumping		543,880,000
11	Net Output for Load (line 9 - line 10) - Kwh	0	(147,084,000)
12	**Cost of Plant**		
13	Land and Land Rights		22,147,163
14	Structures and Improvements	0	39,028,532
15	Reservoirs, Dams, and Waterways	0	74,846,843
16	Water Wheels, Turbines, and Generators	0	69,248,584
17	Accessory Electric Equipment	0	22,059,033
18	Miscellaneous Powerplant Equipment	0	8,381,173
19	Roads, Railroads, and Bridges	0	1,328,336
20	Asset Retirement Costs	0	
21	Total cost (total 13 thru 20)		237,039,664
22	Cost per KW of installed cap (line 21 / 4)		403.9531
23	**Production Expenses**		
24	Operation Supervision and Engineering	0	1,174,231

25	Water for Power	0	
26	Pumped Storage Expenses	0	185,386
27	Electric Expenses	0	1,009,591
28	Misc Pumped Storage Power generation Expenses	0	173,211
29	Rents	0	
30	Maintenance Supervision and Engineering	0	166,490
31	Maintenance of Structures	0	536,487
32	Maintenance of Reservoirs, Dams, and Waterways	0	76,432
33	Maintenance of Electric Plant	0	998,694
34	Maintenance of Misc Pumped Storage Plant	0	360,097
35	Production Exp Before Pumping Exp (24 thru 34)		4,680,619
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)		4,680,619
38	Expenses per kWh (line 37 / 9)		0.0118
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0.0050

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)			
1	Hydro-Neal Shoals												
2	Hydro License												
3	Project #2315	1905	4.41	3.0	6,447,000	14,854,161		286,955		174,533			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1																			
2																			
3																			
4																			
5																			
6																			
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30																			
31																			
32																			
33																			
34																			
35	TOTAL																		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
2									
3									
4									
5									
6									
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9									
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11									
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29									
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31									
32									
33									
34									
35									
36	TOTAL			0	0	0	0	0	0

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	115 KV System	Various	115	230	Various	95.20	15.57	(b)0	Various 115/230	501,903	39,793,606	40,295,510				
2	115 KV System	Various	115	115	Various	1,478.56	101.18	(c)0	Various 115	78,531,495	713,323,658	791,855,153				
3	46 KV System	Various	46	115	Various	43.77		(d)0	Various 46/115	513,128	4,400,909	4,914,038				
4	46 KV System	Various	46	46	Various	575.30	25.77	(e)0	Various 46	2,552,966	60,642,818	63,195,783				
5	33 KV System	Various	33	33	Various	63.62	3.29	(f)0	Various 33	62,375	4,442,316	4,504,691				
6	13.8 KV System	SPA	13.8	46	Various	0.34		1	336mcm 13.8		31,047	31,047				
7	13.8 KV System	Neal Shoals	13.8	14	Wood-SP	11.10		1	336mcm 13.8							
8	13.8 KV System	Neal Shoals	13.8	14	Wood-SP		2.90	2	336mcm 13.8	4,930	638,577	643,507				
9	230 KV System									20,064,652	611,257,001	(g)631,321,652				
10	Canadys	Faber Place	230	230	Wood-H	38.90		1	795mcm							
11	Canadys	Sumter Cpl Tie	230	230	Wood-H	19.06		1	795mcm							
12	Canadys	Urquhart Jct	230	230	Wood-H	85.04		1	1272mcm							
13	Canadys	Williams	230	230	STEEL-SP	53.49		1	1272mcm							
14	Canadys	Yemassee	230	230	Various	33.96		1	Various							
15	CEC (Cola Energy Ctr)	Fold-In	230	230	STEEL-SP	5.88		1	1272mcm							
16	Church Creek	Faber Place #2	230	230	Wood-H	3.97		1	1272mcm							

17	Church Creek	Yemassee	230	230	Various	52.10		1	1272mcm							
18	Cope	Canadys	230	230	STEEL-SP	40.53		2	795mcm							
19	Cope	Orangeburg	230	230	STEEL-SP	22.05		2	795mcm							
20	Denny Terrace	Lyles #1	230	230	STEEL-SP	2.68		2	1272mcm							
21	Edenwood	Lake Murray	230	230	Wood-H	15.25		1	Various							
22	Edenwood	Lake Murray	230	230	STEEL-SP	0.28		2	Various							
23	Edenwood	Owens Steel	230	230	STEEL-SP	0.41		1	1272mcm							
24	Graniteville	Urquhart Jct	230	230	Wood-H	23.90		1	1272mcm							
25	Graniteville Sub #1	Graniteville Sub #2	230	230	STEEL	0.06		1	1272mcm							
26	Hercules Tap		230	230	Wood-H	0.43		1	1272mcm							
27	Hopkins	Fold-In #1	230	230	STEEL-SP	2.84		1	1272mcm							
28	Hopkins	Fold-In #2	230	230	STEEL-SP	0.48		1	1272mcm							
29	Huron	Tap	230	230	Wood-H	0.11		1	1272mcm							
30	Jasper Co	Yemassee #1	230	230	STEEL-SP	39.49		2	1272mcm							
31	Jasper Co	Yemassee #2	230	230	STEEL-SP	39.27		2	1272mcm							
32	Jasper	Purrysburg (Santee) #1	230	230	STEEL-SP	1.24		1	1272mcm							
33	Jasper	Purrysburg (Santee) #2	230	230	STEEL-SP	1.26		1	1272mcm							
34	Lake Murray	Saluda River #1	230	230	STEEL-SP	6.38		2	1272mcm							
35	Lyles	Saluda River #1	230	230	STEEL-SP	4.13		2	1272mcm							
36	Parr	McMeekin	230	230	Wood-H	38.20		1	795mcm							
37	Pepperhill	Mateeba	230	230	Various	8.78		1	various							
38	Pineland	Denny Terrace	230	230	STEEL-SP	8.28		2	1272mcm							
39	Orangeburg East	St. George	230	230	STEEL-SP	24.04		2	1272mcm							
40	St. George	Williams	230	230	STEEL-SP	43.79		1	various							
41	St. George	Summerville #1	230	230	STEEL-SP	65.97		1	1272mcm							
42	St. George	Summerville #2	230	230	STEEL-SP	65.97		1	1272mcm							
43	SRT	St. George	230	230	Wood-H	67.63		2	1272mcm							
44	Summer	Denny Terrace #1	230	230	Wood-H	52.96		1	various							
45	Summer	Parr #1	230	230	Wood-H	0.06		1	1272mcm							
46	Timberlake	Tap	230	230	Wood-SP	8.41		1	1272mcm							
47	VCS1	Denny Terrace	230	230	Various	16.95		2	1272mcm							
48	VCS1	Fairfield #1	230	230	Wood-H	1.09	0.08	1	1272mcm							
49	VCS1	Fairfield #2	230	230	Wood-H	1.13	0.08	1	1272mcm							
50	VCS1	Killian	230	230	STEEL-SP	3.36		1	1272mcm							
51	VCS1	Killian	230	230	STEEL-SP	38.66		2	1272mcm							
52	VCS1	Newport Tie	230	230	STEEL-SP	10.95		1	various							
53	VCS1	Pineland	230	230	Wood-H	5.54		2	1272mcm							

54	VCS1	Pineland	230	230	STEEL-SP	3.38		1	1272mcm							
55	VCS1	VCS2 Bus Tie #1	230	230	STEEL-SP	2.08		1	1272mcm							
56	VCS2	Bush River Tie	230	230	STEEL-SP	11.17		1	various							
57	VCS2	Denny Terrace	230	230	Various	2.78		1	795mm							
58	VCS2	Graniteville	230	230	Wood-H	63.26		1	1272mcm							
59	VCS2	Lake Murray #1	230	230	STEEL-SP	20.53		2	1272mcm							
60	VCS2	Lake Murray #2	230	230	STEEL-SP	22.74		2	1272mcm							
61	VCS2	Saluda River	230	230	STEEL-SP	27.99		2	1272mcm							
62	VCS2	Orangeburg	230	230	STEEL-SP	71.41		2	1272mcm							
63	Vogtle	SRP	230	230	STEEL-H	17.10		2	1272mcm							
64	Wateree	Denny Terrace	230	230	Wood-H	29.55		1	1272mcm							
65	Wateree	Edenwood	230	230	Wood-H	33.70		1	1272mcm							
66	Wateree	Orangeburg	230	230	Wood-H	27.85		1	795mcm							
67	Wateree	Pineland	230	230	Various	0.23		2	1272mcm							
68	Wateree	Pineland	230	230	Various	7.35		1	1272mcm							
69	Wateree	St. George	230	230	Wood-H	45.85		1	1272mcm							
70	Wateree	Sumter Cpl Tie	230	230	Wood-H	0.86		1	1272mcm							
71	Williams	Cainhoy	230	230	Wood-H	17.52		1	1272mcm							
72	Williams	DuPont #1	230	230	Wood-H	6.60		1	1272mcm							
73	Williams	Faber Place #1	230	230	Wood-H	0.01		1	1272mcm							
74	Williams	Faber Place #1	230	230	STEEL-SP	4.69		2	1272mcm							
75	Williams	Faber Place #2	230	230	Tower-H	13.65	6.71	2	1272mcm							
76	Williams Station ESS	Tie	230	230	Concrete	0.08		1	795mcm							
77	Yemassee	Burton	230	230	STEEL-SP	21.31		2	1272mcm							
78	Yemassee (SCEG)	Yemassee (Santee)	230	230	Wood-H	2.93		2	1272mcm							
79	Underground															
80	33 KV System					0.23		2	250mcm		16,443	16,443				
81	46 KV System					0.90		1	750mcm		1,620,606	1,620,606				
82	115 KV System					19.88		1	2250kcm	10,799,766	75,685,469	86,485,234				
83	[a] See Footnote												[b] 418,269	[c] 8,982,606		9,400,875
36	TOTAL					3,698	156	101		113,031,215	1,511,852,450	1,624,883,664	418,269	8,982,606		9,400,875

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

Maintenance expense includes Account No. 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

(b) Concept: NumberOfTransmissionCircuits

Various

(c) Concept: NumberOfTransmissionCircuits

Various

(d) Concept: NumberOfTransmissionCircuits

Various

(e) Concept: NumberOfTransmissionCircuits

Various

(f) Concept: NumberOfTransmissionCircuits

Various

(g) Concept: OverallCostOfTransmissionLine

Total capitalized cost of 230kV System.

(h) Concept: OperatingExpensesOfTransmissionLine

Reported costs in column (l) reflect total costs including balances recorded in Account No. 106 - Completed Construction not Classified. Columns (a) through (i) include statistical data related to unitized plant only.

(i) Concept: MaintenanceExpensesOfTransmissionLine

Operation expense includes Account No. 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION			SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS				LINE COST					
	From	To	Line Length in Miles	Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	Voltage KV (Operating)	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	Construction
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Overhead:																
2	Clemson Wind Turbine 115kv Tap		0.0003	Steel		1		1272	ACSR	A4SH	115		80,864	35,983		116,847	Overground
3	Pepperhill 115kv	Coosaw Creek	0.0002	Steel		1		1272	ACSR	A4SH	115		106,818	39,062		145,880	Overground
4	Midway Sub		0.0086	Steel		1		477	ACSR	A4SH	115		25,092	24,240		49,332	Overground
5	Longwood 115kv		0.0132	Steel		1		1272	ACSR	A4SH	115		1,105,532	464,199		1,569,731	Overground
6	Saluda Hydro-Harbison 115kv		0.0978	Steel		1		1272	ACSR	HLPD	115		5,740,909	3,432,098		9,173,007	
7	VCS1 - DT/PL 230kV Rebld		0.3322	Steel		1		1272	ACSR	HLPD	230		12,669,912	5,857,972		18,527,884	
44	TOTAL		0		0	6	0						19,729,127	9,853,554		29,582,681	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Aiken, Aiken County	Transmission	Unattended	115.00	46.00		28	1				
2	Aiken, Aiken County	Transmission	Unattended	115.00	12.00		22	1				
3	Barnwell, Barnwell County	Transmission	Unattended	115.00	46.00		56	2				
4	Batesburg, City of Batesburg	Transmission	Unattended	115.00	33.00		28	1				
5	Batesburg, City of Batesburg	Transmission	Unattended	115.00	23.00		28	1				
6	Bayview, Mt. Pleasant City	Transmission	Unattended	115.00	23.00		75	2				
7	Blackville 115-46KV, Barnwell County	Transmission	Unattended	115.00	46.00		28	1				
8	Blackville 115-46KV, Barnwell County	Transmission	Unattended	115.00	12.00		28	1				
9	Burton Transmission, Beaufort County	Transmission	Unattended	230.00	115.00		224	1				
10	Burton Transmission, Beaufort County	Transmission	Unattended	115.00	46.00		112	2	4			
11	Cainhoy 230-115kV, Berkeley County	Transmission	Unattended	230.00	115.00		336	1				
12	Cainhoy 230-115kV, Berkeley County	Transmission	Unattended	115.00	23.00		56	2				
13	Calhoun County, Calhoun County	Transmission	Unattended	115.00	46.00		28	1				
14	Calhoun Falls, Calhoun Falls City	Transmission	Unattended	115.00	46.00		50	2				
15	Calhoun Falls, Calhoun Falls City	Transmission	Unattended	46.00	12.00		7	1	1			
16	Canadys Sub, Colleton County	Transmission	Unattended	230.00	115.00		224	1	1			
17	Charleston, Charleston County	Transmission	Unattended	115.00	23.00		67	2				
18	Church Creek, Charleston County	Transmission	Unattended	230.00	115.00		896	3				
19	Coit Gas Turbine, Richland County	Transmission	Unattended	13.80	33.00		56	2				
20	Coit, Richland County	Transmission	Unattended	115.00	23.00		22	1				
21	Coit, Richland County	Transmission	Unattended	115.00	33.00		56	1				
22	Columbia Energy, Calhoun County	Transmission	Unattended	18.00	115.00		250	1				
23	Columbia Energy, Calhoun County	Transmission	Unattended	18.00	230.00		583	2				

24	Columbia Industrial Park, Richland County	Transmission	Unattended	230.00	115.00		336	1				
25	Cope, Orangeburg County	Transmission	Unattended	230.00	115.00		224	1				
26	Cope, Orangeburg County	Transmission	Unattended	23.00	230.00		549	1				
27	Denmark, City of Denmark	Transmission	Unattended	115.00	46.00		56	2				
28	Denny Terrace, Richland County	Transmission	Unattended	230.00	115.00		672	2				
29	Edenwood, City of Cayce	Transmission	Unattended	230.00	115.00		448	2				
30	Faber Place, City of North Charleston	Transmission	Unattended	115.00	23.00		73	3				
31	Faber Place, City of North Charleston	Transmission	Unattended	230.00	115.00		672	2	1			
32	Fairfax, Allendale County	Transmission	Unattended	115.00	46.00		56	2				
33	Fairfield Pumped Storage, Fairfield County	Transmission	Unattended	13.80	230.00		717	4	1			
34	Goose Creek, Hanahan City	Transmission	Unattended	230.00	115.00		336	1				
35	Graniteville #1, Aiken County	Transmission	Unattended	115.00	46.00		56	2				
36	Graniteville #1, Aiken County	Transmission	Unattended	230.00	115.00		448	2				
37	Graniteville #2, Aiken County	Transmission	Unattended	230.00	115.00		336	1				
38	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.80	115.00		60	1				
39	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.20	115.00		147	1				
40	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.80	4.16		6	1				
41	Hamlin, Charleston County	Transmission	Unattended	115.00	23.00		112	3	1			
42	Hampton, Hampton County	Transmission	Unattended	115.00	46.00		84	3	2			
43	Hanahan, Hanahan City	Transmission	Unattended	115.00	23.00		78	3				
44	Hanahan, Hanahan City	Transmission	Unattended	115.00	46.00		56	2				
45	Hardeeville, Jasper County	Transmission	Unattended	115.00	46.00		28	1				
46	Hobcaw, Charleston County	Transmission	Unattended	115.00	24.94		28	1				
47	Hopkins, Richland County	Transmission	Unattended	230.00	115.00		672	2				
48	Jasper 230kV, Jasper County	Transmission	Unattended	18.00	230.00		700	3				
49	Jasper 230kV, Jasper County	Transmission	Unattended	21.00	230.00		500	1				
50	Kendrick, Richland County	Transmission	Unattended	115.00	23.00		84	3	1			
51	Killian, Richland County	Transmission	Unattended	230.00	115.00		336	1				
52	Lake Murray, Lexington County	Transmission	Unattended	230.00	115.00		672	2	1			
53	Lyles, Richland County	Transmission	Unattended	230.00	115.00		336	1	1			
54	Lyles, Richland County	Transmission	Unattended	115.00	23.00		56	2				
55	Lyles, Richland County	Transmission	Unattended	115.00	35.00		56	1	1			
56	McCormick, McCormick County	Transmission	Unattended	115.00	46.00		58	2	1			
57	McMeekin, Lexington County	Transmission	Unattended	13.20	115.00		350	2				
58	Orangeburg #1, Orangeburg County	Transmission	Unattended	115.00	46.00		81	3	1			
59	Orangeburg East 230KV, Orangeburg County	Transmission	Unattended	230.00	115.00		672	2				
60	Parr Gas Turbine, Fairfield County	Transmission	Unattended	13.20	115.00		98	2	1			

61	Parr Hydro, Fairfield County	Transmission	Unattended	2.30	13.80		25	3				
62	Parr Steam, Fairfield County	Transmission	Unattended	115.00	13.20		34	1				
63	Pepperhill, Charleston County	Transmission	Unattended	230.00	115.00		336	1				
64	Pineland, Richland County	Transmission	Unattended	230.00	115.00		672	2				
65	Rader, Richland County	Transmission	Unattended	115.00	23.00		45	2				
66	Ridgeville, City of Ridgeville	Transmission	Unattended	115.00	46.00		28	1				
67	Ridgeville, City of Ridgeville	Transmission	Unattended	115.00	23.00		28	1				
68	Ritter, Colleton County	Transmission	Unattended	230.00	115.00		336	1				
69	Saluda Hydro, Lexington County	Transmission	Unattended	13.20	115.00		275	5				
70	Saluda Hydro, Lexington County	Transmission	Unattended	115.00	23.00		66	2				
71	Saluda River, Lexington County	Transmission	Unattended	230.00	115.00		336	1				
72	Santee, Orangeburg County	Transmission	Unattended	230.00	46.00		28	1				
73	Santee, Orangeburg County	Transmission	Unattended	115.00	46.00		28	1				
74	Santee, Orangeburg County	Transmission	Unattended	230.00	115.00		140	1				
75	Savannah River, Federal Property	Transmission	Unattended	230.00	115.00		672	2				
76	St. Andrews, Charleston City	Transmission	Unattended	115.00	23.00		22	1				
77	St. George, Dorchester County	Transmission	Unattended	115.00	46.00		28	1				
78	Stevens Creek Hydro, Columbia Cnty Ga.	Transmission	Unattended	2.40	46.00		28	4				
79	Stevens Creek Sub, Columbia Cnty Ga.	Transmission	Unattended	115.00	46.00		28	1	1			
80	Summerville, Berkeley County	Transmission	Unattended	230.00	115.00		672	2				
81	Thomas Island, Charleston County	Transmission	Unattended	115.00	23.00		75	2				
82	Trenton, Edgefield County	Transmission	Unattended	115.00	23.00		37	1	1			
83	Trenton, Edgefield County	Transmission	Unattended	115.00	46.00		56	2				
84	Urquhart 115KV, Aiken County	Transmission	Unattended	115.00	13.20		325	6				
85	Urquhart 115-46KV, Aiken County	Transmission	Unattended	115.00	46.00		48	2				
86	Urquhart 230KV, Aiken County	Transmission	Unattended	18.00	230.00		467	2	1			
87	Urquhart Gas Turbine, Aiken County	Transmission	Unattended	13.20	115.00		176	3	1			
88	V. C. Summer Substation, Fairfield County	Transmission	Unattended	22.00	230.00		1232	1	1			
89	Ward, Saluda County	Transmission	Unattended	230.00	115.00		364	2	1			
90	Ward, Saluda County	Transmission	Unattended	115.00	23.00		22	1				
91	Ward, Saluda County	Transmission	Unattended	115.00	33.00		28	1				
92	Wateree Plant, Richland County	Transmission	Unattended	21.00	230.00		1008	2	1			
93	Wateree Plant, Richland County	Transmission	Unattended	230.00	13.80		75	2				
94	Williams Gas Turbine, Berkeley County	Transmission	Unattended	13.20	115.00		70	1				
95	Williams St., Columbia City	Transmission	Unattended	115.00	23.00		60	2				
96	Williams Station, Berkeley County	Transmission	Unattended	20.00	230.00		785	1	1			
97	Williams Station, Berkeley County	Transmission	Unattended	115.00	230.00		560	2				

98	Williams Station, Berkeley County	Transmission	Unattended	230.00	4.16		93	2				
99	Williams Station, Berkeley County	Transmission	Unattended	230.00	23.00		101	2				
100	Williston Industrial Park , Barnwell County	Transmission	Unattended	115.00	46.00		32	6				
101	Yemassee, City of Yemassee	Transmission	Unattended	230.00	115.00		784	3				
102	Blackville West, Barnwell County	Transmission	Unattended	115.00	46.00		56	1				
103	Distribution Substations:											
104	Adams Run, Charleston County	Distribution	Unattended	115.00	23.00		50	2				
105	Adams Run, Charleston County	Distribution	Unattended	115.00	46.00		112	2				
106	Aiken #2, Aiken County	Distribution	Unattended	115.00	12.00		51	2				
107	Aiken #3, Aiken County	Distribution	Unattended	115.00	12.00		51	2				
108	Aiken Hampton Avenue, Aiken City	Distribution	Unattended	115.00	12.00		28	1				
109	Aiken Industrial Park, Aiken City	Distribution	Unattended	46.00	23.00		11	1				
110	Aiken-Steifeltown, Aiken County	Distribution	Unattended	115.00	12.00		22	1				
111	Allendale, Allendale City	Distribution	Unattended	115.00	12.00		22	1				
112	Arrowwood Road, Richland County	Distribution	Unattended	115.00	23.00		22	1				
113	Ashley Phosphate, City of North Charleston	Distribution	Unattended	115.00	23.00		60	2				
114	Bacon's Bridge, Summerville City	Distribution	Unattended	115.00	23.00		37	1				
115	Baldock, Allendale County	Distribution	Unattended	115.00	12.00		22	1				
116	Bamberg Central, Bamberg City	Distribution	Unattended	43.80	12.00		14	2				
117	Barnwell City, Barnwell City	Distribution	Unattended	46.00	12.00		11	1				
118	Barnwell Heights, Barnwell City	Distribution	Unattended	46.00	12.00		11	1				
119	Barnwell Industrial Park, Barnwell County	Distribution	Unattended	43.80	12.00		11	1				
120	Batesburg City, Lexington County	Distribution	Unattended	33.00	8.00		11	1				
121	Bayfront, Charleston City	Distribution	Unattended	115.00	23.00		40	1				
122	Beaufort Central, Beaufort City	Distribution	Unattended	115.00	12.00		28	1				
123	Beaufort Industrial Park, Beaufort County	Distribution	Unattended	115.00	12.00		22	1				
124	Bee Street, Charleston County	Distribution	Unattended	115.00	14.40		202	4				
125	Beech Island, Aiken County	Distribution	Unattended	46.00	12.00		11	1				
126	Bellwright, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				
127	Belmont, Richland County	Distribution	Unattended	115.00	23.00		50	2				
128	Belvedere, North Augusta City	Distribution	Unattended	115.00	12.00		50	2				
129	Blackville 46-12KV, Barnwell County	Distribution	Unattended	46.00	12.00		11	1				
130	Bluffton, Beaufort County	Distribution	Unattended	115.00	23.00		56	2				
131	Blythewood, Richland County	Distribution	Unattended	115.00	23.00		75	2				
132	Boney Rd. , Fairfield County	Distribution	Unattended	115.00	23.00		45	2				
133	Boone Hill, Dorchester County	Distribution	Unattended	115.00	23.00		60	2				
134	Bowman, Orangeburg County	Distribution	Unattended	115.00	8.00		11	1				

135	Brookwood, West Columbia City	Distribution	Unattended	115.00	23.00		28	1				
136	Burton Central, Beaufort County	Distribution	Unattended	115.00	12.00		56	2				
137	CAE Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		28	1				
138	Cainhoy, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				
139	Calhoun Street, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
140	Callawassie Island, Jasper County	Distribution	Unattended	115.00	23.00		28	1	1			
141	Carlisle, Carlisle City	Distribution	Unattended	115.00	23.00		21	4				
142	Carolina Bay, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
143	Cayce, City of Cayce	Distribution	Unattended	33.00	8.00		13	2				
144	Center Sub, Aiken County	Distribution	Unattended	46.00	23.00		11	1				
145	Chapin Business Park, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
146	Charleston Airport, N Charleston City	Distribution	Unattended	115.00	23.00		40	1				
147	Charlotte Street, Charleston City	Distribution	Unattended	115.00	14.40		101	4				
148	Church Creek 115-23kV, Charleston City	Distribution	Unattended	115.00	23.00		75	2				
149	Circle Drive, Richland County	Distribution	Unattended	115.00	8.00		22	1				
150	Clearwater, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
151	Cloverleaf, Aiken County	Distribution	Unattended	115.00	12.00		22	1	1			
152	Colonial Heights, Richland County	Distribution	Unattended	115.00	23.00		22	1				
153	Columbia Airport, Springdale City	Distribution	Unattended	115.00	23.00		22	1				
154	Columbia Industrial Park, Richland County	Distribution	Unattended	115.00	23.00		37	1				
155	Congaree Creek, Cayce City	Distribution	Unattended	115.00	23.00		28	1				
156	Congaree Vista South, Richland County	Distribution	Unattended	115.00	23.00		37	1				
157	Cooper River, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				
158	Coosaw, Charleston County	Distribution	Unattended	115.00	23.00		37	1				
159	Cromer Rd, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
160	Deer Park, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
161	Denmark Industrial Park, Denmark City	Distribution	Unattended	46.00	12.00		11	1	1			
162	Dentsville, Richland County	Distribution	Unattended	115.00	23.00		45	2				
163	Dixiana, Lexington County	Distribution	Unattended	115.00	23.00		65	2				
164	East Columbia, Richland County	Distribution	Unattended	115.00	23.00		37	1				
165	Edmund, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
166	Estill, Estill City	Distribution	Unattended	46.00	12.00		14	1				
167	Estill Southside, Estill City	Distribution	Unattended	46.00	12.00		25	2	1			
168	Eutawville, Orangeburg County	Distribution	Unattended	115.00	23.00		50	2				
169	Fairfax Central, Fairfax City	Distribution	Unattended	46.00	12.00		18	2				
170	Five Points, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
171	Fort Johnston Road, Charleston County	Distribution	Unattended	115.00	23.00		50	2				

172	Frogmore, Beaufort County	Distribution	Unattended	115.00	23.00		28	1				
173	Gardens Corner, Beaufort County	Distribution	Unattended	115.00	23.00		22	1				
174	Gaston, Lexington County	Distribution	Unattended	115.00	23.00		50	2				
175	Gilbert, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
176	Gills Creek, Richland County	Distribution	Unattended	115.00	23.00		37	1				
177	Grays Hill, Beaufort County	Distribution	Unattended	115.00	12.00		22	1				
178	Greengate, Richland County	Distribution	Unattended	115.00	23.00		37	1				
179	Grove Street, Charleston City	Distribution	Unattended	115.00	14.40		22	1				
180	Hampton City, Hampton County	Distribution	Unattended	46.00	12.00		21	2				
181	Hanahan Switching, Berkeley County	Distribution	Unattended	46.00	4.16		14	2	1			
182	Harbison, Lexington County	Distribution	Unattended	115.00	23.00		50	2				
183	Hardeeville, Hardeeville City	Distribution	Unattended	115.00	23.00		28	1	1			
184	Herrin, Allendale County	Distribution	Unattended	46.00	12.00		11	1				
185	Holly Hill, Holly Hill City	Distribution	Unattended	115.00	23.00		50	4	1			
186	Houndslake, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
187	Howard Street, Richland County	Distribution	Unattended	33.00	8.00		11	1				
188	Irmo Town, Irmo City	Distribution	Unattended	115.00	23.00		56	2				
189	Isle of Palms, Isle of Palms City	Distribution	Unattended	115.00	23.00		50	2				
190	Jack Primus, Berkeley County	Distribution	Unattended	115.00	23.00		37	1				
191	Jackson 46-12kV, Aiken County	Distribution	Unattended	46.00	12.00		11	1				
192	Jackson Street, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
193	James Island, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
194	James Prioleau, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
195	Jasper 115kV Construction, Jasper County	Distribution	Unattended	115.00	23.00		11	1				
196	Johnston 115-23KV, Edgefield County	Distribution	Unattended	115.00	23.00		22	1				
197	Kilbourne Park, Richland County	Distribution	Unattended	115.00	23.00		60	2				
198	Killian, Richland County	Distribution	Unattended	115.00	23.00		37	1				
199	Kingswood, Richland County	Distribution	Unattended	115.00	23.00		50	2				
200	Ladies Island, Beaufort County	Distribution	Unattended	115.00	23.00		50	2				
201	Lake Carolina, Richland County	Distribution	Unattended	115.00	23.00		65	2				
202	Lake Murray Training, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
203	Langley, Aiken County	Distribution	Unattended	115.00	12.00		22	1				
204	Laurel Bay 115-12KV, Beaufort County	Distribution	Unattended	115.00	12.00		28	1				
205	Leesville 115-23KV, Lexington County	Distribution	Unattended	115.00	23.00		28	1				
206	Lexington 115-23kV, Lexington County	Distribution	Unattended	115.00	23.00		65	2	1			
207	Lexington East Side, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
208	Lexington Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		75	2	1			

209	Lexington West Side, Lexington County	Distribution	Unattended	115.00	23.00		75	2				
210	Lower Richland, Richland County	Distribution	Unattended	115.00	23.00		60	2				
211	Maryville, Charleston County	Distribution	Unattended	115.00	23.00		37	1				
212	McCormick City 115-12KV, McCormick Cnty	Distribution	Unattended	115.00	12.00		11	1	1			
213	Meadowbrook, Beaufort County	Distribution	Unattended	115.00	23.00		22	1				
214	Meeting Street, Charleston County	Distribution	Unattended	115.00	14.40		28	1				
215	Middleburg Mall, Richland County	Distribution	Unattended	115.00	8.00		22	1				
216	Midway, Union County	Distribution	Unattended	115.00	13.80		20	1	2			
217	Midway, Union County ground bank	Distribution	Unattended	13.80	4.80		1	3				
218	Midway, Union County	Distribution	Unattended	115.00	23.00		1	22				
219	Mt Pleasant, Charleston County	Distribution	Unattended	115.00	23.00		77	2				
220	Muller Avenue, Richland County	Distribution	Unattended	115.00	8.00		22	1				
221	Muller Avenue, Richland County	Distribution	Unattended	115.00	23.00		28	1				
222	Navy Yard 115-23kV, Federal Property, SC	Distribution	Unattended	115.00	23.00		28	1				
223	Navy Yard 115-23kV, Federal Property, SC	Distribution	Unattended	115.00	13.80		22	1				
224	Neeses, Orangeburg County	Distribution	Unattended	46.00	8.00		11	1				
225	Network, Richland County	Distribution	Unattended	115.00	13.80		67	3				
226	North 46-8kV, Orangeburg County	Distribution	Unattended	46.00	8.00		11	1				
227	North Augusta, Aiken City	Distribution	Unattended	115.00	12.00		28	1				
228	North Bridge Terrace, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
229	North Naval Weapons, Federal Property	Distribution	Unattended	115.00	13.80		22	1				
230	North Rhett, North Charleston City	Distribution	Unattended	115.00	23.00		28	1				
231	Northpointe Business Park, Charleston County	Distribution	Unattended	115.00	23.00		37	1				
232	Northwoods Mall, North Charleston City	Distribution	Unattended	230.00	23.00		75	2	1			
233	Okatie, Jasper County	Distribution	Unattended	115.00	23.00		28	1				
234	Old Fort, Dorchester County	Distribution	Unattended	115.00	23.00		60	2				
235	Osceola Park, Charleston County	Distribution	Unattended	115.00	23.00		75	2				
236	Palmetto Commerce Park, Charleston City	Distribution	Unattended	115.00	23.00		65	2				
237	Park Street, Columbia City	Distribution	Unattended	115.00	13.80	0	56	2	0			
238	Parr Hill 115-23kV, Fairfield County	Distribution	Unattended	115.00	23.00		22	1				
239	Pelion, Lexington County	Distribution	Unattended	115.00	23.00		45	2				
240	Pendleton Street, Columbia City	Distribution	Unattended	115.00	8.00		45	2				
241	Pine Hill 230-23kV, Dorchester County	Distribution	Unattended	230.00	23.00		37	1				
242	Piney Woods Road, Richland County	Distribution	Unattended	115.00	23.00		37	1				
243	Platt Springs Rd., Lexington County	Distribution	Unattended	115.00	23.00		51	2				
244	Pontiac, Richland County	Distribution	Unattended	230.00	23.00		75	2				
245	Port Park, Hanahan City	Distribution	Unattended	115.00	23.00		22	1				

246	Port Royal, Port Royal City	Distribution	Unattended	115.00	12.00		28	1				
247	Pritchardville, Beaufort County	Distribution	Unattended	115.00	23.00		37	1				
248	Quail Hollow, Lexington County	Distribution	Unattended	115.00	23.00		37	1	2			
249	Raborn Pointe, North Augusta City	Distribution	Unattended	115.00	12.00		22	1				
250	Rantowles, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
251	Red Bank 115-23kV, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
252	Red House Rd, Charleston County	Distribution	Unattended	46.00	23.00		45	2	1			
253	Richland Mall, Forest Acres City	Distribution	Unattended	115.00	8.00		45	2				
254	Ridgeland, Jasper County	Distribution	Unattended	115.00	23.00		22	1	1			
255	Riverland Terrace, Charleston County	Distribution	Unattended	115.00	23.00		22	1				
256	Riverland Terrace, Charleston County	Distribution	Unattended	23.00	4.16		4	1				
257	Rosewood, Columbia City	Distribution	Unattended	33.00	8.00		21	2				
258	Sage Mill Ind Park, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
259	Saluda County, Saluda County	Distribution	Unattended	115.00	23.00		23	1				
260	Sandhill, Richland County	Distribution	Unattended	115.00	23.00		75	2				
261	Santee 46-8kV, Orangeburg County	Distribution	Unattended	46.00	8.00		21	2				
262	Savage Road, Charleston County	Distribution	Unattended	115.00	23.00		67	3				
263	Saxe Gotha Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		74	2				
264	SC Research Association, Richland County	Distribution	Unattended	115.00	23.00		50	2				
265	Seven Mile, North Charleston City	Distribution	Unattended	115.00	23.00		23	1				
266	Sewee 115-23KV, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
267	Shell Point, Beaufort County	Distribution	Unattended	46.00	12.00		28	2	1			
268	Silver Bluff Rd, Aiken County	Distribution	Unattended	115.00	12.00		23	1				
269	South Main, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
270	South Main, Columbia City	Distribution	Unattended	115.00	23.00		37	1				
271	Sparkleberry, Richland County	Distribution	Unattended	115.00	23.00	23	38	1				
272	Sparkleberry, Richland County	Distribution	Unattended	115.00	23.00		37	1				
273	Springdale, Lexington County	Distribution	Unattended	115.00	23.00		45	2	1			
274	St. George 115-12kV, Dorchester County	Distribution	Unattended	115.00	12.00		28	1				
275	St. Helena Island, Beaufort County	Distribution	Unattended	115.00	23.00		51	2				
276	St. Matthews 46-23kV, Calhoun County	Distribution	Unattended	46.00	23.00	23	23	2	1			
277	Stono Park, Charleston City	Distribution	Unattended	115.00	23.00		37	1				
278	Summer Construction, Fairfield County	Distribution	Unattended	115.00	23.00		23	1				
279	Summerville Central, Berkeley County	Distribution	Unattended	115.00	23.00		40	1				
280	Summerville Industrial Park, Dorchester County	Distribution	Unattended	115.00	23.00		50	2				
281	Summerville Plaza, City of Summerville	Distribution	Unattended	115.00	23.00		37	1				
282	Summerville-Ladson, Charleston County	Distribution	Unattended	115.00	23.00		65	2				

283	Swansea, Lexington County	Distribution	Unattended	46.00	23.00		11	1				
284	Sweetwater, Aiken County	Distribution	Unattended	115.00	12.00		56	2				
285	Ten Mile, Charleston County	Distribution	Unattended	115.00	23.00		22	1				
286	Timberlake, Lexington County	Distribution	Unattended	230.00	23.00		37	1	1			
287	Uptown, Columbia City	Distribution	Unattended	115.00	23.00		37	1	1			
288	Uptown, Columbia City	Distribution	Unattended	115.00	8.00		23	1				
289	Varnville, Varnville City	Distribution	Unattended	46.00	12.00		11	1				
290	Victory Gardens, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
291	Wagener, Wagner City	Distribution	Unattended	46.00	8.00		11	1				
292	Walterboro 115-23KV, Walterboro City	Distribution	Unattended	115.00	23.00		22	1				
293	Walterboro Forest Hill, Walterboro City	Distribution	Unattended	115.00	23.00		40	1				
294	Walterboro Ind Park, Walterboro City	Distribution	Unattended	115.00	23.00		28	1				
295	Walterboro South Side, Walterboro City	Distribution	Unattended	115.00	23.00		22	1				
296	West Columbia, West Columbia City	Distribution	Unattended	33.00	8.00		18	2				
297	White Gables, Dorchester County	Distribution	Unattended	115.00	23.00		37	1				
298	White Rock, Richland County	Distribution	Unattended	115.00	23.00		50	2	1			
299	Whitehall, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
300	Williston, Williston City	Distribution	Unattended	115.00	12.00		22	1				
301	Winnsboro, Winnsboro City	Distribution	Unattended	115.00	23.00		45	2				
302	Woodfield Park, Richland County	Distribution	Unattended	115.00	23.00		45	2				
303	Yemassee Central, Yemassee City	Distribution	Unattended	115.00	23.00		22	1				
304	Calhoun Street, Columbia City	Distribution	Unattended	115.00	23.00		37	1				
305	Garners Ferry, Richland County	Distribution	Unattended	115.00	23.00		28	1				
306	Smoaks - Collenton County	Distribution	Unattended	46.00	13.80		6	1				
307	Smoaks - Collenton County	Distribution	Unattended	115.00	23.00		28	1				
308	May River - Beaufort County	Distribution	Unattended	115.00	23.00		37	1				
309	Cope Dist - Orangeburg County	Distribution	Unattended	115.00	23.00		28	1				
310	Ulmer - Allendale County	Distribution	Unattended	46.00	12.00		7	1				
311	CMC Steel #3 Sub	Distribution	Unattended	115.00	13.80		28	1				
312	Cross County 115-23KV Sub	Distribution	Unattended	115.00	23.00		37	1				
313	Eastover Solar 230KV Switching Stat	Distribution	Unattended	230.00	23.00		0	0				
314	Hampton Solar II Sub	Distribution	Unattended	46.00	12.00		0	0				
315	Hugh Leatherman Sub	Distribution	Unattended	115.00	13.80		28	1				
316	Huntley Solar 230KV Sub	Distribution	Unattended	230.00	23.00		0	0				
317	Lily Solar 115KV	Distribution	Unattended	115.00	23.00		0	0				
318	Long Star Solar 230KV Switching Sta	Distribution	Unattended	230.00	23.00		0	0				
319	Longwood Sub	Distribution	Unattended	115.00	13.80		75	2				

320	May River	Distribution	Unattended	115.00	23.00		37	1				
321	Michelin Cleo Sub	Distribution	Unattended	13.80	4.16		0	0				
322	Midlands Solar 115KV Sub	Distribution	Unattended	115.00	23.00		0	0				
323	Palmetto Plains Solar 115KV Sub	Distribution	Unattended	115.00	23.00		0	0				
324	Peony Solar 46KV Sub	Distribution	Unattended	46.00	12.00		0	0				
325	Seabrook Solar 115KV Sub	Distribution	Unattended	115.00	23.00		0	0				
326	Shaw Creek Solar	Distribution	Unattended	230.00	23.00		0	0				
327	TWE Bowman Solar 115KV Sub	Distribution	Unattended	115.00	23.00		0	0				
328	Waters Edge	Distribution	Unattended	46.00	4.16		0	1				
329	Westpoint Stevens #1	Distribution	Unattended	46.00	4.00		6	1				
330	Whiskey Rd Sub	Distribution	Unattended	115.00	12.00		28	1				
331	Under 10,000 KVA (35)	Distribution	Unattended				186					
332	TotalDistributionSubstationMember						7,680	321	23			0
333	TotalTransmissionSubstationMember						23,790	183	26			0
334	Total						31,470	504	49			0

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	[(a)] Charges for Costs and Services	Dominion Energy Services, Inc.		231,984,218
3	[(b)] Coal and transportation services received	South Carolina Generating Company, Inc.	151	1,142,092
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Shared resources (labor and related travel expenses) for refueling outage work at Millstone Nuclear Power Station	Dominion Energy Nuclear Connecticut - Millstone	[(c)] See Footnote	485,276
22	Rental Fee for Use of Assets	Dominion Energy Services, Inc.	454/493	3,675,709
42				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/22/2024	Year/Period of Report End of: 2023/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

The transactions below represent costs and services billed by Dominion Energy Services, Inc. to the Company during the reporting period.

FERC Account	Description	Charges
107	Construction Work in Progress	$ 11,234,141
143	Other Accounts Receivable	48,806
174	Miscellaneous Current & Accrued Assets	1,729
182.2	Unrecovered Plant & Regulatory Study Costs	62,341
182.3	Other Regulatory Assets	332,830
183	Preliminary Survey & Investigation Charges	83,122
186	Miscellaneous Deferred Debits	332,463
408.1	Taxes Other than Income Taxes - Utility Operating	7,481,216
408.2	Taxes Other than Income Taxes - Other Income & Ded	103,620
416	Costs & Expenses of Merchandising, Jobbing & Contr	293,695
419	Interest & Dividend Income	(383)
421	Miscellaneous Nonoperating Income	413,713
426.1	Other Income Deductions - Donations	335,084
426.2	Other Income Deductions - Life Insurance Premium	19,169
426.3	Other Income Deductions - Penalties	52
426.4	Other Income Deductions - Civic/Political Activity	4,114,287
426.5	Other Income Deductions	3,753,525
431	Other Interest Expense	311,780
501	Steam Operation - Fuel	121,062
506	Steam Operation - Miscellaneous Steam Power Expens	33,055
524	Nuclear Operation - Miscellaneous Nuclear Power Ex	3,771,613
549	Other Power Operations - Miscellaneous Other Power	20,931
571	Transmission Maintenance - Overhead Lines	58,222
588	Distribution Operation - Misc Distribution Expense	1,462,637
593	Distribution Maintenance - Overhead Lines	(5)
840	Other Storage Operation - Supervision/Engineering	61,257
841	Other Storage Operation - Labor/Expenses	6,150
870	Gas Distribution Op - Supervision and Engineering	758,966
874	Gas Distribution Op - Mains and Services Exps	1,817,221
879	Gas Distribution Op - Customer Installations Exps	306,286
880	Gas Distribution Op - Other Expenses	2,648,590
893	Gas Distribution Maint - Meters/House Regulators	636,617
903	Customer Accounts - Customer Records & Collections	25,125,825
905	Customer Accounts - Miscellaneous Expenses	6,292,278
920	Administrative & General Operation - Salaries	82,584,713
921	Administrative & General Operation - Office Supplies & Expenses	25,434,142
923	Administrative & General Operation - Outside Services Employed	11,833,406
924	Administrative & General Operation - Property Insurance	(6,236)
925	Administrative & General Operation - Injuries & Damages	8,234
926	Administrative & General Operation - Employee Pensions & Benefits	13,409,578
928	Administrative & General Operation - Regulatory Commission Expenses	898,868
930.1	Administrative & General Operation - General Advertising Expenses	4,103
930.2	Administrative & General Operation - Miscellaneous General Expenses	3,916,296
931	Administrative & General Operation - Rents	11,025,463
932	Administrative & General Maintenance -Maintenance of General Plant	1,239,093
935	Administrative & General Maintenance - Maintenance of General Plant	9,594,661
	TOTAL	**$ 231,984,218**

Departmental Services and Expense	Charges	Allocation Method
Accounting Services	$ 7,299,264	(A) Headcount, (B) Accounts Payable Processing, (C) Fixed Assets, (N) Accounts Payable P-Card
Auditing	1,303,596	(Q) O&M
Business Services	17,822,150	(I) Square Footage, (J) Fleet, (A) Headcount, (Q) O&M, (R) Aviation
Capital / Assets	12,095,433	
Corporate Planning	10,316,392	(M) Capitalization
Corporate Secretary	638,259	(Q) O&M
Customer Service	32,311,478	(P) Customer Payments
Environmental Compliance	4,822,022	(Q) O&M
Energy Marketing	629,921	(Q) O&M
Executive and Administration	16,049,027	(Q) O&M
External Affairs	11,076,449	(Q) O&M
Human Resources	7,911,305	(A) Headcount
Information Technology, Electronic Transmission & Computer Services	46,919,615	(D) Number of Customers, (F) Number of Users (EID's), (G) Other Computer Applications, (H) Telecom
Interest Expense	3,953,725	(E) Affiliate Billings
Investor Relations	184,648	(Q) O&M
Legal and Regulatory	5,637,361	(Q) O&M
Office Space	1,008,546	(K) Headcount Corporate Offices
Operations	30,657,038	(Q) O&M, (T) Gas Volumes
Other	(665,162)	(Q) O&M
Rates and Regulatory	2,671,950	(Q) O&M
Risk Management	630,811	(L) Insurance Premiums
Software/ Hardware Pooling	9,695,317	(F) Number of Users (EID's)
Supply Chain	5,088,363	(S) Purchases
Tax	1,304,745	(O) Taxes
Treasury / Finance	2,621,965	(M) Capitalization
TOTAL	**$ 231,984,218**	

Legend		Allocation Methodology
(A)	Headcount	Number of Dominion Company employees as of the preceding December 31st.
(B)	Accounts Payable Processing	Number of Dominion Company accounts payable documents processed during the preceding year ended December 31st.
(C)	Fixed Assets	Dominion Company fixed assets added, retired or transferred during the preceding year ended December 31st.
(D)	Number of Customers	Number of Dominion Company customers at the end of the preceding year ended December 31st.
(E)	Affiliate Billings	Portion of direct and allocated costs.
(F)	Number of Users (EID's)	Number of Dominion Company Employee users at the end of the preceding year ended December 31st.
(G)	Other Computer Applications	Number of Dominion Company usage of specific computer systems at the end of the preceding year ended December 31st.
(H)	Telecom	Number of Dominion Company telecommunications units at the end of the preceding year ended December 31st.
(I)	Square Footage	Square footage of Dominion Company office space as of the preceding year ended December 31st.
(J)	Fleet	Number of Dominion Company vehicles as of the preceding December 31st.
(K)	Headcount Corporate Offices	Headcount at corporate offices as of the previous December 31st.
(L)	Insurance Premiums	Dominion Company insurance premiums for the preceding year ended December 31st.
(M)	Capitalization	Total Dominion Company capitalization (Debt and Equity) recorded at preceding December 31st.
(N)	Accounts Payable P-Card	Dollar value of Dominion Company purchases on company credit cards for the preceding year ended December 31st.
(O)	Taxes	The sum of the total income and total deductions as reported for Dominion Consolidated Federal Income Tax purposes on the last return filed.
(P)	Customer Payments	Number of Dominion Company customer payments processed during the preceding year ended December 31st.
(Q)	O&M	Total operating expenses, excluding purchased gas expense, purchased power expense (including fuel expense), other purchased products and royalties, depreciation, depletion, and amortization, and taxes other than income for the preceding year ended December 31st for the affected Dominion Companies.
(R)	Aviation	A combination of O&M as noted above and flight days for the previous two years.
(S)	Purchases	Dollar value of Dominion Company purchases for the preceding year ended December 31st.
(T)	Gas Volumes	Throughput of gas volumes purchased for each Dominion Company for the preceding year ended December 31st.

(b) Concept: DescriptionOfNonPowerGoodOrService
As a result of the merger integration with Dominion Energy, South Carolina Fuel Company, Inc. ("SCFC", an affiliate of DESC which is fully consolidated herein) transitioned from its legacy fuel management system to the system used by Dominion Energy and also integrated its cash management processes into those used by Dominion Energy. As a result, certain fuel and related transportation purchases were initially paid by South Carolina Generating Company, Inc. ("GENCO"). Cash corrections will be made between SCFC and Genco in Q1 2024.
(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies
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